Ferrer, Nathaniel

From: Soenen, Philippe R [PNS3@PGE.COM]
Sent: Wednesday, August 04, 2010 6:39 PM
To: Pick, Greg
Cc: Grebel, Terence; Braico, Kevin
Subject: DCPP correspondence on GL 89-13
Attachments: Outgoing.zip; Incoming.zip

<<Outgoing.zip>> <<Incoming.zip>>
Greg,

Per your request, attached are zip files containing all of the DCPP incoming and outgoing correspondence associated with GL 89-13. Please let me know if you need any additional information.

Philippe Soenen

Pacific Gas & Electric
142 Cross St. Suite 200
San Luis Obispo, CA 93401
Office: 805.781.9782
Cell: 805.459.3701

POLICY ISSUE
(Notation Vote)

March 15, 1994 SECY-94-066

FOR: The Commissioners

FROM: James M. Taylor
Executive Director for Operations

SUBJECT: EVALUATION OF ISSUES DISCUSSED IN SECY-92-314, CURRENT LICENSING BASIS FOR OPERATING PLANTS"

PURPOSE :

To provide the results of further staff evaluation of issues identified in SECY-92-314, which involve (1) licensee commitments outside the FSAR and (2) the licensees' understanding of design bases in terms of scope and relationship to the current licensing basis (CLB).

To inform the Commission of staff initiatives which address additional issues and follow-up actions listed in SECY-92-314.

To respond to the recommendations made by the Office of Policy Planning (OPP) concerning issues related to the CLB.

SUMMARY :

In 1991, during the Commission's deliberations on the license renewal initiative, an issue arose about the possible need for, or utility of, compiling the CLB for all operating plants. Although the principles upon which the license renewal rule, 10 CFR Part 54, are predicated involve the acceptability and maintenance of the CLB, the Commission was interested in the utility of compiling the CLB for currently operating reactors. In November 1991, the Commission directed the staff to provide information and recommendations

NOTE: TO BE MADE PUBLICLY AVAILABLE WHEN THE FINAL SRM IS MADE AVAILABLE

CONTACTS:
Eric J. Leeds/NRR
504-1133

Scott C. Flanders/NRR
504-1172

concerning CLB compilation for currently operating reactors and current industry practices for updating the final safety analysis report (FSAR). The staff responded to the Commission in SECY-92-314 dated September 10, 1992 recommending that the Commission (1) end the formal pilot program for compiling the CLB, (2) not require compilation of the CLB, and (3) not revise the interpretation of 10 CFR 50.71 to include the entire CLB.

In conducting the activities that led to these conclusions, the staff identified issues related to specific elements of the CLB that warranted additional staff action. The staff's principal concern was that an element of the CLB, licensee commitments that are not contained in the plant's FSAR, is not controlled by a regulatory process that {1) defines licensee commitments, (2) provides licensees with a process for changing these commitments, and (3) specifies reporting requirements for commitments that are changed. The staff proposed a series of actions to further examine the issues.

The staff evaluation of issues identified in SECY-92-314 included week-long audits of seven licensee programs to (1) determine how licensees identify track, implement, and change commitments, and (2) examine licensees' understanding of the relationship between design bases as defined in 50.2 and the CLB as defined in 10 CFR Part 54. The audits focused on a specific category of docketed licensee commitments, those not included in either a facility's license or in its FSAR. Such commitments, while considered part of a facility's CLB as defined in 10 CFR 54.3, are not subject to a formal change process and can be legally changed without NRC approval or notification. Although these commitments are not currently governed by a regulatory change and notification process, the staff found that all seven of the audited licensees had established programs that identified these commitments, ensured their implementation, evaluated the impact of potential commitment changes, and provided for NRC notification. The staff did not identify any safety significant issues requiring immediate action and concluded that the CLB was being maintained for all audited issues. However, the staff found that the current situation has resulted in licensee and staff uncertainties regarding appropriate interactions between the licensees and NRC for commitment changes. As a result, application of licensee and staff resources is not as efficient as is desirable. The staff audits did not find any evidence that the term "design bases" needs further clarification as it is used within the regulatory process. The staff found that licensees conducting design basis reconstitution or documentation programs recognized the difference and understood the relationship between the plant's design bases and its licensing basis.

The Regulatory Review Group (RRG), a group assembled to identify where increased flexibility in the regulatory process could be made available to licensees with little or no direct safety impact, has recommended changes to the regulatory process which include proposals that would address many of the concerns and followup actions identified in SECY-92-314. The staff has prepared an implementation plan for the RRG recommendations and submitted it to the Commission in SECY-94-003. The issues and followup actions include: (1) review of the current 50.59 process, (2) review of the FSAR update rule,

50.71(e), (3) possible modification of the definition of CLB and incorporation of the definition into both Part 50 and Part 54, and (4) providing guidance on what constitutes a commitment and the types of controls to be placed on changing commitments.

In response to a Commission request for a review of CLB issues and before the staff completed its evaluation of certain SECY-92-314 issues, OPP proposed recommendations to resolve the issues discussed in, or related to, SECY-92-314. In its report, OPP proposed both a definition of CLB different from the definition of CLB contained in 10 CFR 54.3 and the actions necessary to implement its proposed CLB definition. Neither staff nor OPP identified safety significant issues that would warrant the changes proposed by OPP.

In summary, this paper is intended to provide the Commission with the results of further staff evaluation of issues in SECY-92-314 regarding commitments outside the FSAR and relationship of the plant design basis to the CLB. The staff concludes that there is no indication that licensees view compliance with commitments which are outside the FSAR as discretionary and that the CLB is being maintained for all audited issues.

BACKGROUND:

In 1991, during the Commission's deliberations on the license renewal initiative, an issue arose about the possible need for, or utility of, compiling the CLB for all operating plants. Although the principles upon which the license renewal initiative are predicated involve the acceptability and maintenance of the CLB, the Commission was interested in the utility of compiling the CLB for currently operating reactors. It should also be noted that the term "CLB" is defined in 10 CFR 54.3 but is not defined in 10 CFR Part 50 for operating reactors. In its Staff Requirements Memorandum (SRM) of November 29, 1991, the Commission directed the staff to provide information and recommendations concerning CLB compilation for currently operating reactors and current industry practices for updating the FSAR. The staff responded to the Commission in SECY-92-314 dated September 10, 1992, recommending that the Commission (1) end the formal pilot program for compiling the CLB, (2) not require compilation of the CLB, and (3) not revise the interpretation of 10 CFR 50.71 to include the entire CLB.

However, in conducting the activities that led to these conclusions, the staff identified issues related to the CLB that warranted additional evaluation. The principal issue was that an element of the CLB, licensee commitments that are not contained in the plant's FSAR, is not controlled by a regulatory process that (1) defines licensee commitments, (2) provides licensees with a process for changing these commitments, and (3) specifies reporting requirements for commitments that are changed. The staff also identified that some licensees were confused about the relationship between the "design bases," as defined in 10 CFR 50.2, and the CLB, as defined in 10 CFR Part 54. The staff committed to carry out a series of actions to further examine and resolve the issues.

On September 29, 1992, Commissioner Curtiss requested that the staff and OGC answer questions regarding the issues discussed in SECY-92-314. In a response, dated December 4, 1992 (Enclosure 1), the staff indicated that although the issues did not involve significant safety concerns, further evaluation of the SECY-92-314 issues was warranted to determine any actions needed to ensure that regulatory requirements and guidance are clear and are being properly implemented by the licensees.

On October 28, 1992, the Commission directed OPP to systematically review and analyze the issues discussed in SECY-92-314. In its response, OPP-92-02, "Current Licensing Basis for Operating Plants," of November 30, 1992, OPP proposed a definition of CLB different from the definition of CLB contained in 10 CFR 54.3. In its report, OPP also recommended (1) establishing a definition of CLB in Part 50 for operating reactors, (2) revising the current definition of CLB in 10 CFR 54.3 to reflect the definition established for Part 50 and, (3) considering changes to 10 CFR 50.59, 50.71(e), and 50.109 on the basis of the implications of the established definition of CLB.

On May 28, 1993, the RRG, a group assembled to identify where increased flexibility in the regulatory process could be made available to licensees with little or no direct safety impact, issued its report for public comment. In its report, the RRG referenced the issues discussed in SECY-92-314 and recommended actions to resolve the issues. The staff has prepared an implementation plan for the RRG recommendations and forwarded it to the Commission in SECY-94-003.

During the preparation of this paper the Commission issued an SRM dated October 15, 1993, which returned SECY-92-314 to the staff for further consideration. The Commission requested that the staff integrate current information, such as the response to the OPP report on current licensing basis, in formulating recommendations concerning compilation of the CLB and current industry practice in updating the FSAR.

DISCUSSION:

In developing SECY-92-314, the staff conducted onsite audits and a public workshop to collect information for answers to the Commission's questions on the relationship between the CLB and FSAR, and the usefulness of compiling the CLB for operating reactors. The staff performed audits at 14 plants, completing each in approximately 1 day. For the audits, the staff focused on a limited set of technical issues for which actions were requested by the NRC after the FSAR update rule was issued in 1980 and, in most cases, after the operating license was issued for the facility audited. The staff assessed the amount of information added to the updated FSARs (UFSARs) as a result of these issues and, to a limited extent, the processes used by licensees for managing the resulting commitments. The issues identified by the staff in SECY-92-314 were as follows:

1. "No clear process is defined for making chances to the CLB (licensee commitments) that is not included in the FSAR. The licensee may make changes to the facility as described in the FSAR in accordance with

10 CFR 50.59. However, the NRC has not issued regulatory guidelines for changes to the CLB not contained in the UFSAR."

2. "No industry-wide agreement exists on a definition of CLB (i.e. licensee commitments) for operating reactors. There is no agreement throughout the industry on the interpretation of the definition of "commitment" in 10 CFR 54.3.

3. "Accuracy of the docket with respect to the CLB. As a result of the differing interpretations and the lack of a clearly defined process for making changes to commitments outside the scope of 10 CFR 50.59, some licensees have not docketed changes made to some licensing basis commitments."

4. "No clear understanding exists for "design bases" in terms of its scope and its relationship to the CLB. During the CLB workshop, the staff found confusion among the licensees over "design bases" as defined by 10 CFR 50.2."

The first three issues concern licensees' written commitments for ensuring compliance with and operation within applicable NRC requirements. These commitments were made in docketed licensing correspondence, such as licensee responses to NRC bulletins, generic letters, and enforcement actions and licensee commitments documented in NRC safety evaluations or as described in licensee event reports. SECY-92-314 described this aspect of the CLB as Those portions of the CLB outside of the FSAR" since such commitments may not affect the plant FSAR and, if modified, are not required to be reported in updated FSAR submittals. Such commitments can be changed without either NRC approval or notification. The remaining SECY-92-314 issue concerns the element of the CLB involving the plant-specific design bases information defined in the most recent FSAR as required by 10 CFR 50.71. To address these issues, the staff committed to carry out follow-on efforts to (1) define or clarify the terms "CLB,. "commitment," and "design bases" for operating reactors, (2) ensure commitments are changed appropriately and reflected on the docket, and (3) evaluate proposed changes to 10 CFR 50.2, 10 CFR 50.59, and 10 CFR 50.71(e) to ensure the FSAR, design basis documentation, docketed correspondence, and plant records are complete and that processes for controlling and using the CLB are clear.

Subsequent to submitting SECY-92-314, the staff provided additional information and clarification of the issues in a memorandum dated December 4, 1992, from the Executive Director of Operations to Commissioner Curtiss. Specifically, the staff emphasized the relatively narrow focus of the 1-day audits and noted that the language used in SECY-92-314 may have implied a greater safety significance than the staff intended. The staff noted that the audit findings did not raise significant safety concerns for operating reactors. Additionally, the staff indicated that additional actions would be taken to ensure that the regulatory process and licensee programs related to commitment changes are adequate to ensure that the CLB is being maintained.

To accomplish this, the staff initiated a more intensive examination of the SECY-92-314 issues to better understand the licensees' programs in these areas. The staff conducted week-long team audits at seven plants, representing different NSSS vendors, vintages, and regions, to assess licensees' processes for controlling commitments that are part of the plants' CLB. The sites were selected to provide a representative sample of the industry, including utilities with multiple nuclear sites and utilities with single nuclear units. The sample included sites with a spectrum of regulatory performance characteristics as indicated by the NRC's systematic assessment of licensee performance (SALP) process. The purpose of the audits was to examine licensees' practices in commitment management. Commitment management includes the processes licensees use to identify, track, and ensure implementation of commitments. It also includes the processes licensees use to maintain commitments so that committed actions, whether hardware modifications or procedural changes, are not inadvertently changed or deleted after implementation. Finally, commitment management includes the processes licensees use to decide if they should inform the NRC when a commitment is changed. The audit teams also examined licensees' design basis reconstitution programs to determine licensees' understanding of design bases and its relationship to the CLB.

The audit teams reviewed the seven licensees' programmatic and administrative controls for commitment management. To examine the programs in actual practice, the teams reviewed the status of licensee commitments made to the NRC in response to specific safety issues. Five of these issues were specifically selected because of their generic safety significance. The remaining issues were specific to the individual licensees and included commitments made in licensee event reports (LERs) and responses to notices of violation (NOVs). Enclosure 2 contains a list of the plants audited and the issues reviewed.

The audit teams relied on standard NRC inspection practices in conducting the review of licensee commitments. While this was a special effort focused on the review of licensee commitments, the NRC routinely audits the status of licensee commitments during team inspections and certain resident inspector inspections. In conducting the audits, the teams performed system walkdowns, reviewed applicable documentation (including design change packages, training records, and procedures), and interviewed the licensees' personnel. The teams examined between 50 to 75 commitments at each site, some from docketed correspondence as early as 1981, and reviewed the initial implementation and the current status of each commitment. At the completion of each site audit, the teams reviewed their findings with the licensee and documented the findings in an audit report. Enclosure 3 is a copy of one of the seven audit reports. The staff is in the process of issuing the audit reports to each licensee audited as part of the docket.

Overall, the staff found that each licensee audited had established programs for identifying and implementing its commitments to the NRC. In conducting the audits, the staff did not find any safety significant commitments that licensees had not implemented or failed to maintain. The majority of licensees had developed formal commitment management programs that tracked identification and implementation of commitments. These licensees also had

programs for maintenance of commitments so that subsequent actions, such as revision of a procedure, did not inadvertently modify or delete a committed action. The licensees, without formal commitment management programs, used action tracking systems and computerized data bases to accomplish these same functions. The staff found very few examples in which a licensee changed a commitment without (1) deliberate consideration of the underlying safety intent of the commitment or (2) docketing the commitment change when it involved a possible change in intent. The few examples in which a licensee inadvertently changed a commitment, or chose not to docket the change, were fully evaluated by the audit teams and found to be of very low significance.

ISSUES IDENTIFIED IN SECY-92-314

1. "No clear process is defined for making chances to the CLB (licensee commitments) that is not included in the FSAR. The licensee may make changes to the facility as described in the FSAR in accordance with 10 CFR 50.59. However, the NRC has not issued regulatory guidelines for changes to the CLB not contained in the UFSAR."

Figure 1 is a conceptual illustration of the regulatory processes for changing different elements of the CLB. With the exception of this specific category of licensee commitments, as shown in the figure, each level in the NRC's hierarchical structure includes a change mechanism for licensees to use to control changes to their facilities' CLB.

REGULATORY PROCESS	50.90, 50.92, 2.202	50.71(e) 50.59	50.54 50.12	No Prescribed Process
CLB Elements:	Tech Specs		QA	Licensee Commitments to:
	License Conditions	FSAR	Security	GLs
			EP Exemptions	Bulletins LERs
	Orders			NOVs Others

Figure 1: Regulatory Processes Applicable for Changing, and Reporting, Various Elements of the Current Licensing Basis

Although no formal change or reporting requirements exist, the staff found that the licensees audited have developed programs and processes for managing and controlling changes to such commitments. As a result of these programs, the staff audits did not identify any safety issues associated with the current situation for changing commitments. There was no indication that, as a result of the lack of a required change process, licensees viewed compliance with commitments as completely discretionary. Although there is no defined

process for licensees to follow when changing commitments, the staff found that licensees evaluate commitment changes. The staff found, through discussions with the licensees, NRC resident inspectors, several NRC regional section chiefs, and NRR project managers, that an informal process, common across the industry, has developed. A licensee wishing to change a commit" went performs an evaluation of the change and typically discusses the change with the NRC resident inspector staff, the NRC regional section chief, or the NRR project manager. In almost all cases, the NRC staff advises the licensee to docket the change in a letter to the agency. These letters commonly inform the NRC of the change and do not request confirmation or approval. In conducting the audits, the staff identified only two instances in which commitments were purposely changed and not reported on the docket to the NRC. Staff evaluation of both instances determined that enforcement action was not appropriate. Both instances are considered to involve changes with low safety significance.

Although the NRC has not promulgated regulatory requirements or explicit guidelines for licensees to use for changing written commitments that are not contained in the license or the FSAR, the NRC expects that licensees will maintain the intent of their commitments. Despite the considerable legal flexibility for changing commitments which is afforded by the NRC, the Commission's expectation that commitments will be met is briefly addressed in 10 CFR Part 2, Appendix C, D.(1), Notices of Deviation." For many such commitments, for example, information provided by licensees addresses how compliance with NRC regulations is or will be attained. While the regulatory process permits licensees to make changes to the specifics of such commitments without NRC interaction, it requires that the regulations continue to be met. The regulatory process also provides the NRC with means (e.g., inspection program activities) to evaluate licensee commitment changes and to take appropriate enforcement action if or when necessary.

While no safety issues were identified, the staff audits did indicate that many licensees and NRC staff do not have a clear understanding of when commitments can be changed without NRC interaction. In practice, as noted previously, licensees interact with the NRC before changing most commitments, regardless of safety significance. In the absence of a defined process, licensees, very often with informal staff encouragement, opt for a conservative approach regarding staff interaction. An effort to develop staff guidance on what constitutes a commitment and the types of controls to be placed on changing commitments is being carried out in response to the recommendations of the RRG. Additionally, the staff will reassess the need for rulemaking after staff guidance is implemented. Since safety-significant issues have not been identified by the staff audits, the staff withdraws the statement contained in SECY-92-314 that a change process must be devised and required of licensees to ensure the underlying safety interest of the commitment is preserved."

2. "<u>No industry-wide agreement exists on a definition of CLB (i.e.. licensee commitments) for operating reactors</u>. There is no agreement throughout the industry on the interpretation of the definition of "commitment" in 10 CFR 54.3."

The staff's audits confirmed that there are some differences among licensees in their interpretation of the term "commitment." Commitment is not defined in 10 CFR Part 50 or 10 CFR Part 54, although the term is currently referenced in 23 separate regulations. However, there is an industry working group, the Regulatory Commitment Tracking Group (RCTG), that has developed a definition of commitment, which a number of licensees have adopted. The purpose of the RCTG, which includes about 30 utilities, is to provide licensees the opportunity to share information and techniques for commitment management.

The staff found that five of the seven licensees audited had developed a definition for commitment, some adopting or basing their definition on the RCTG's definition, for their plant staff to use when dealing with regulatory issues. Despite differences among licensees in their detailed interpretations of commitment, the staff found only one issue concerning what constituted a commitment in practice. This issue involved three licensees that took explicit credit for existing programs in their response to generic letters or bulletins but did not include these programs in their commitment management systems. The staff believes that if a licensee uses an existing program to address a regulatory concern, then a traceable correlation of the program to the concern would be necessary for the licensee to adequately evaluate subsequent changes to the program. When the staff identified this anomaly to the three licensees involved, the licensees agreed with the staff and indicated that they would review their definition of commitment and/or their process for identifying and changing commitments. With the exception of this issue, there were no disagreements between the staff and the licensees audited concerning the actions the licensees had committed to accomplish. Although different licensees used slightly different definitions of commitment, the safety issues important to the NRC were being appropriately managed.

3. "Accuracy of the docket with respect to the CLB. As a result of the differing interpretations and the lack of a clearly defined process for making changes to commitments outside the scope of 10 CFR 50.59, some licensees have not docketed changes made to some licensing basis commitments."

Licensees are not legally required to report changes to commitments that are not included in the license or the FSAR. In practice, however, the staff audits found very few instances in which licensees changed the intent of a commitment and did not provide docketed notification to the NRC. The few instances were evaluated in detail and found to be of very low safety significance. All of the licensees audited, relying on the judgment of their licensing and compliance managers, deliberately considered whether a change to a commitment should be communicated to the NRC. Most of the audited licensees typically placed a change to a commitment on the docket based on a change to the commitment's intent or a change to the scheduled implementation date. Several licensees indicated that they would also formally notify the NRC of a change to a commitment on the basis of their perception of the importance of the issue to the NRC, even if they believed that the intent had not been changed. Most licensees also noted that if they were unsure about the appropriate course of action, they

would typically notify the NRC of the change. In addition, the audits found that informal staff guidance to the licensees encourages the licensees to report changes to commitments on the docket.

The staff did find several examples of commitments that had been inadvertently changed by the licensees' staff. However, these instances involved commitments made by licensees in LERs and NOVs and were of very low significance. For example, in response to an NOV, a licensee committed to ensure that the fire Marshall kept all master equipment keys in his possession. Contrary to this, the staff found that the process for controlling the keys had been changed and that the keys were now kept in a locked box in the shift engineer's office. However, the licensing group, responsible for deciding whether to inform the NRC of changes to commitments, was not informed of the change. Although the licensee's failure to notify the NRC of the change was inconsistent with its established process, such notification is not required by existing regulations and in this case, the staff believes that the licensee had preserved the intent of its commitment (i.e., the master equipment keys were adequately controlled).

An issue also has been raised about the accuracy of docketed CLB information and the Commission's requirement, for license renewal, that each plant's CLB be maintained for any renewal period. Specifically, since some commitments included in the 10 CFR 54.3 definition of CLB can be changed without docketed NRC notification, does the current regulatory process ensure a plant's CLB is maintained?

Although some licensee written commitments can be changed without docketed notification to the NRC, licensees are generally making such notifications when they change the intent or scheduled implementation of a commitment. More importantly, the staff has found that licensees are evaluating commitment changes to ensure that the underlying safety intent of the commitment will be maintained. It is the preservation of the underlying intent of such licensee commitments, rather than the implementation specifics, which is fundamental to safety. Additionally, although written notification of a commitment change is not currently required, the NRC inspection program provides a vehicle for verifying that the CLB is being maintained. If, as a result of NRC inspections, problems with commitment changes and their impact on the safety focus of the CLB are identified, the regulatory process provides for the possibility of both immediate regulatory action (e.g., orders) and the future imposition of explicit regulatory requirements for commitment changes. As noted previously, the staff will follow through on the RRG implementation plan recommendations which will examine new initiatives for enhancing the regulatory process in the area of commitments.

4. “<u>No clear understanding exists for "design bases" in terms of its scone and its relationship to the CLB</u>. During the CLB workshop, the staff found confusion among the licensees over "design bases” as defined by 10 CFR 50.2."

The staff found that the audited licensees that were conducting design basis reconstitution or documentation programs recognized the difference and understood the relationship between the plant's design bases and its licensing basis. As defined by 10 CFR 54.3, the CLB includes the plant-specific design bases information defined in 10 CFR 50.2 as documented in the most recent FSAR as required by 10 CFR 50.71. Several of the licensees indicated that one of the reasons for performing these programs was to clearly identify the design and the licensing bases of the facility. Clarification of the plant design bases and the licensing basis and the margins between the two provided licensees with the knowledge to make sound changes to their facility, in accordance with 10 CFR 50.59, without adversely affecting safety.

In conducting design basis reconstitution programs, several of the audited licensees had performed a thorough review of historical commitments based on system or topic to ensure that the licensing basis was accurately described. Where discrepancies were identified, the licensees added the commitment to their tracking systems for implementation and continued maintenance.

A more detailed study of licensees' design basis reconstitution or documentation programs is documented in NUREG-1397, Tan Assessment of Design Control Practices and Design Reconstitution Programs in the Nuclear Power Industry." This study involved six utilities (five of the six were different than those audited for this report) and found that most of the programs reviewed contained system-specific licensing commitments and exceptions.

EVALUATION OF RECOMMENDATIONS BY THE OFFICE OF POLICY PLANNING

On October 28, 1992, the Commission requested that OPP systematically review and analyze the CLB issues discussed in SECY-92-314 and to discuss the regulatory significance of these issues. On the basis of its review, OPP proposed a definition of CLB (OPP-92-02) different from the current definition of CLB in 10 CFR 54.3. The purpose of the OPP proposal was to more clearly define those issues that require NRC approval before licensee modification and to eliminate from the current CLB definition those items that the licensee can change without prior staff approval. The OPP also recommended (1) establishing a definition of CLB in 10 CFR Part 50 for operating reactors, (2) revising the definition of CLB in 10 CFR 54.3 to reflect the definition established for 10 CFR Part 50 and, (3) considering changes to 10 CFR 50.59, 50.71(e), and 50.109 based on the implications of the established definition of CLB.

The OPP recommendation is that the CLB should be redefined to represent the delineation of how applicable regulations will be met, as evaluated and relied upon by the NRC and documented in safety evaluation reports (SER), the facility license, or technical specifications or otherwise imposed on the licensee. The OPP recommendation would establish the CLB as "...the minimum safety envelope within which operations must take place." The key objective is to include within the CLB only items which must be approved by the NRC before any change is made. For NRC SERs, only that information identified as <u>essential</u> to demonstrate how regulations will be met would be considered as part of the CLB. The principal advantages of

such an approach are stated to be increased certainty about what changes require NRC approval and the elimination from the current CLB definition items that can be changed as a result of the licensees' own initiative.

As explained in the Statement of Considerations (SOC) for 10 CFR Part 54 and in OPP-92-~02, the regulatory process is necessarily broad in scope. The definition of CLB in Part 54 was developed to recognize and take credit for the broad scope of NRC activities as the basis for an exclusive license renewal focus on aging effects in the period of extended operation. The Commission indicated in the SOC that as a result of the full scope of ongoing regulatory activities, issues other than aging need not be evaluated for license renewal. This recognition of the full scope of regulatory activities is viewed as appropriate and reflects the existing regulatory approach. Although the regulatory process is hierarchical, it is structured deliberately to ensure the closest scrutiny is given to issues which have the greatest safety significance. It is the entire process, however, including aspects which can be changed without NRC approval, which is utilized by the agency in carrying out its overall safety mission. The OPP view that the Part 54 CLB definition is inappropriate Because it includes items which may be changed by the licensee's own initiative and are not part of the NRC review and approval process contrasts with the existing hierarchical regulatory process.

The OPP recommendation to define the CLB as that information that would require NRC approval prior to change is not considered practical. Although OPP suggests that the CLB information (i.e., information that must be approved by NRC before any change) be defined so that it must be only that information relied upon for meeting applicable regulations, this is not current regulatory practice. For example, NRC staff SERs have not been developed to ensure that all information that is provided by a licensee to establish regulatory compliance (e.g., FSAR), and that could require NRC approval before change, is included and specifically identified in the SER. As a result, license-specific application of the OPP definition of CLB would, as a practical matter, require an evaluation process with uncertainties which could reduce the suggested benefit of the CLB redefinition. Implementation of the definition would require licensees and NRC staff to determine which items are included within the OPP definition of CLB. Additionally such a change to 10 CFR Part 50 would not be expected to be justified on the basis of the evaluation criteria of 10 CFR 50.109. The staff did not identify any safety significant issues during the recently completed site audits that would warrant the changes proposed by OPP. OPP also expressed the view that the current CLB situation does not adversely affect the safety of operating reactors.

CONCLUSIONS:

The staff found that the audited licensees had developed programs and processes for managing the commitments they make to the NRC and for controlling changes to these commitments. There was no indication that, as a result of the lack of a required change process, licensees viewed compliance with commitments as discretionary. Although licensees are not legally required to report changes to commitments that are not included in the license and the FSAR, the staff found very few examples in which a licensee

changed a commitment without (1) deliberate consideration of the underlying safety intent of the commitment or (2) docketing the commitment change when it involved a possible change in intent. The staff did not identify any safety significant issues requiring immediate action.

2. Although the NRC has not promulgated regulatory requirements or explicit guidelines for licensees to use for changing written commitments that are not contained in the license or the FSAR, the NRC expects that licensees will maintain the intent of their commitments. While the regulatory process permits licensees to make changes to the specifics of some commitments without NRC interaction, the process also provides the NRC with the means (e.g., inspection program activities) to evaluate licensee commitment changes and to take appropriate enforcement action if necessary.

3. Although the process for maintaining and changing some commitments is not subject to formal regulatory controls and does permit unreported changes to some commitments, the staff concludes that licensees' conservative implementation of their administrative processes and the NRC's regulatory process as described in the Statements of Consideration accompanying 10 CFR Part 54 ensures that the CLB will be maintained to provide an acceptable level of safety. Although licensees may change some documented commitments without formal NRC interaction, the staff concludes that licensees ensure that the underlying safety intent of their commitments will be maintained.

4. The staff audits identified that many licensees and NRC staff do not have a clear understanding of when commitments can be changed without NRC interaction. This has led most licensees to act conservatively, interacting with NRC staff and reporting changes to commitments regardless of safety significance. This in turn, has resulted in an inefficient expenditure of licensee and NRC resources. The staff's implementation plan for RRG recommendations includes an effort to develop guidance on what constitutes a commitment and the types of controls to be placed on commitments.

5. The staff did not identify a need to further clarify the term "design bases" as it is used within the regulatory process.

6. Neither the staff nor OPP identified any safety significant issues that would warrant the changes proposed by OPP. The staff believes that the CLB definition contained in Part 54 is appropriate and, that the OPP redefinition contrasts with the existing regulatory process, and would not provide a practical approach for achieving significant regulatory improvements.

COORDINATION:

The Office of the General Counsel has reviewed this paper and has no legal objection to its content.

RECOMMENDATIONS:

That the Commission:

1. Approve the staff's recommendations presented in SECY-92-314. The recommendations of SECY-92-314 were that the Commission:

   a. end the program that sought volunteers to compile their CLB,
   b. not require licensees to compile the CLB within a single document,
   c. not revise the interpretation of the FSAR update rule to include the entire CLB.

2. Not adopt the recommendations forwarded in OPP-92-02.

3. Make this paper publicly available with SECY-92-314 and the October 15, 1993, SRM.

Enclosures:
1. December 4, 1992, Memorandum from EDO to Commissioner Curtiss
2. Audit Plants and Issues
3. Hope Creek Audit Report

Commissioners' comments or consent should be provided directly to the Office of the Secretary by COB Wednesday, March 30, 1994.

Commission Staff Office comments, if any, should be submitted to the Commissioners NLT Wednesday, March 23, 1994, with an information copy to the Office of the Secretary. If the paper is of such a nature that it requires additional review and comment, the Commissioners and the Secretariat should be apprised of when comments may be expected.

DISTRIBUTION:
Commissioners
OGC
OCAA
OIG
OPA
OCA
OPP
EDO
ACRS
SECY

ENCLOSURE 1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

December 4, 1992

MEMORANDUM FOR: Commissioner Curtiss

FROM: James M. Taylor
Executive Director for Operations

SUBJECT: CURRENT LICENSING BASIS

I have enclosed answers to the questions you asked about SECY 92-314, "Current Licensing Basis for Operating Plants." The answers to questions 1 and 8a include discussions on the legal ramifications of certain staff findings documented in SECY 92-314. These answers have been coordinated with OGC.

The staff conducted the current licensing basis (CLB) audits and workshop, as discussed in SECY 92-314, to collect information for the Commission's questions on the relationship between the CLB, the final safety analysis report (FSAR), and the usefulness of compiled CLBs for operating reactors. There were 14 audits in all, each taking approximately one day to complete. The audits were narrowly focused on the content of the FSARs end the processes for managing commitments and design bases. As a result of the audit findings, the staff conducted a CLB workshop which featured open discussions on the processes for managing and changing the CLB. Some of the language used in SECY 92-314 may have implied greater safety significance then the staff intended. While some weaknesses were observed, the findings and conclusions in SECY 92-314 should be understood in context that all of the audited facilities have developed basic programs and processes in response to the NRC's requirements for managing changes to the CLB. The principal requirements for managing these changes are contained in Appendix B to 10 CFR Part 50, 10 CFR 50.59, 10 CFR 50.90, 10 CFR 50 54 (a), 10 CFR 50.54 (p), 10 CFR 50.54(q), 10 CFR 50.71(e), 10 CFR 50.72, 10 CFR 50.73 and plant-specific license conditions. The audits focused on a limited set of technical issues for which actions were requested by the NRC after the FSAR update rule was Issued in 1980 and, in most cases, after the operating license (OL) was issued for the facility audited. The audits assessed the amount of information added to the Updated FSARs (UFSARs) as a result of these few issues and, to a limited extent, the processes used by licensees for managing commitments and design bases.

The principal findings from the audits of the 14 facilities are as follows:

1. FSARs for the audited facilities included only a portion of the CLB. This is consistent with the discussion in the Statements of Consideration for 10 CFR Part 54 about the CLB for license renewal.

CONTACT:
M. Virgilio
504-1353

2. The processes for evaluating changes to the facility against the CLB commitments and design bases vary significantly between licensees and there were indications of weaknesses in the processes used at some of the facilities audited.

3. Most of the audited facilities are improving the management of commitments and design bases. These improvements are a result of design reconstitution programs, commitment tracking systems, and electronic information storage and retrieval systems.

The FSAR update requirements contained in 10 CFR 50.71(e) have not been interpreted by either the licensees or the staff to require new commitments and design bases developed in response to rules, generic letters, bulletins and enforcement actions, and those proposed in licensee event reports be included in the FSAR. As a result, the staff found more than half of the audited facilities were updating the FSAR to only reflect the effects of changes to the facility and its programs. In general, the scope of the FSARs was not being expanded to address issues not originally included at the time of OL issuance. The Statement of Consideration for 10 CFR Part 54 recognized that the complete CLB for a facility is not included in the FSAR.

The staff found that some of the audited facilities rely on a manual capability to search information contained on the docket and that others use electronic databases and retrieval systems to recall documents that contain commitments and design bases. The thoroughness of the search, the ease of retrieval, and the ability of the licensee's staff to access the documents varied among the licensees, depending on the method used. At some of the audited facilities it took hours to recall the docketed correspondence on an issue with only a few of the licensee’s staff able to perform this task.

All of the audited facilities were performing safety assessments to support changes to the facility and its programs. However, some of the audited facilities had neither procedures that would require all docketed correspondence on a particular issue to b reviewed and evaluated before implementing a change to the facility nor other mechanisms to ensure commitments would not be changed without licensee review and subsequent written notification to the NRC.

The staff found that licensees use a variety of processes for assessing the reportability of changes to commitments and design bases that are not included in the FSAR. Not all of these processes include notifying the NRC and docketing the change. Thus, the audits and CLB workshop disclosed that the NRC docket file may not necessarily contain a description of the current manner in which every commitment to the NRC is carried out. Licensee changes to important commitments are communicated on the docket through vehicles such as FSAR updates (including 50.59 summaries), LER supplements, and letters. Changes to minor commitments may not be placed on the docket if the subject 13 not covered by the FSAR or an LER, or is otherwise not deemed by the licensee to be sufficiently important to warrant additional correspondence to the NRC. The CLB workshop discussions indicated that such

changes are often, but not always, discussed orally with resident inspectors or other members of the regional or NRR staff. Nevertheless, the result is that the docket may not necessarily include a description of how all commitments (a part of the CLB as now defined in 10 CFR Part 54) are currently met. While the original commitment remains on the docket, the licensee may have subsequently Altered the manner in which the commitment is fulfilled. While the stiff proposals in SECY 92-314 are meant to further investigate the acceptability of current licensee practices, we do not at this time believe that current practices represent a significant safety concern for operating reactors.

No specific safety concerns were identified either during the limited audits performed by the staff or during the CLB workshop. However, based on the audit and workshop findings and the November 30, 1992, OPP Report on the CLB, further evaluation is warranted to determine the actions needed to ensure that regulatory requirements and guidance are clear and are being properly implemented by the licensees.

Original signed by
James H. Sniezak

For:
James M. Taylor
Executive Director
for Operations

Enclosure:
Response to Commissioner Curtiss'
Questions on SECY 92-314

cc w/enclosure:
The Chairman
Commissioner Rogers
Commissioner Remick
Commissioner DePlanque
SECY
OGC

DISTRIBUTION

Central File	J. Roe	P. Noonan	OPA
PDIV-1 r/f	M. Virgilio	A. Bill Beach	OCA
AD r/f	J. Larkins	E. Beckjord	EDO r/f
J. Scinto	E. Jordan	J. Taylor	T. Gibbons
W. Russell	J. Sniezek	B. Clayton	J. Blaha
D. Crutchfield	F. Gillespie	H. Thompson	J. Partlow
T. Murley/F. Miraglia		D. Wigginton	
NRR Mail Room w/incoming			

Enclosure

ANSWERS TO COMMISSIONER CURTISS' QUESTIONS
ABOUT SECY 92-314

1. Question

What are the legal ramifications of the staff's findings in SECY 92-314 for the agency's approach to license renewal? Specifically, what imp u t do these findings have on the first of the two basic generic principles upon which the license renewal rule was based: that the regulatory process is adequate to ensure that the licensing bases of all currently operating plants provide and maintain acceptable level of safety for operation so that operation will not be inimical to public health and safety or common defense and security?

Answer

The staff's audit findings end the discussions at the current licensing basis (CLB) workshop raise questions that need to be resolved concerning two aspects of the Part 54 license renewal rulemaking: (1) the first principle of license renewal, and (11) the Commissions determination that ~ finding of compliance of a plant with its current licensing basis is not required for issuance of a renewed license.

The first principle of license renewal concerns the adequacy of the NRC's regulatory process for assuring that the licensing basis of all currently-operating nuclear power plants provide and maintain an acceptable level of safety, so that operation will not be inimicable to the public health and safety or common defense and security. (56 FR 64943, 61946 December 13, 1991). That principle, along with the second principle of license renewal[1], formed the basis for the Commission's conclusion that n formal license renewal review by the NRC of r plant's CLB against the full range of requirements on safety and common defense and security is not necessary, stack such a review would not add significantly to safety or common defense and security. See 56 FR 64945, 64947. The Commission also concluded that a finding of compliance of a plant with its current licensing basis at the time of renewal is not required. See 56 FR 64943, 64951-52.

The Commission's conclusions that neither ~ safety review garnet the full range of safety requirements nor ~ finding of compliance with the CLB are necessary at the time of renewal were based upon two findings: (1) the adequacy of the NRC's regulatory process, end (11) the licensee's activities to update (maintain) the CLB and ensure compliance with the CLB. 55 FR at 64947-52. The NRC's regulatory process consists of many distinct elements, including the review of operating events, the review of generic safety and unresolved safety issues, the systematic evaluation program, activities under the

[1] 'The second principle is that each plant's current licensing basis must be maintained throughout the renewal term. See 56 FR 64943, 64947.

severe accident program, and the NRC's inspection, audit, and enforcement activities. It "as recognized that from time to time there would be instances of licensee noncompliance with Commission regulatory requirements and licensee commitments, but the Commission believed that the regulatory process was sufficient to rectify these instances and to generally assure adequate protection of the public health and safety and compliance with the license.

The licensees' programs for updating its CLB end assuring compliance with the licensing basis also encompass many discrete licensee programs/activities. These include programs end procedures for properly recognizing and appropriately controlling NRC-initiated and licensee-initiated changes to the facility’s licensing basis, developing the necessary documentation to support such changes, and making any necessary changes to the FSAR.

Many of these elements of the NRC regulatory process and the licensee programs are unaffected by the results of the 14-plant audit and the CLB workshop. However, the results of the audit end CLB workshop do raise questions regarding whether all licensees: 11) have adequate measures for controlling changes to the licensing basis, (11) properly consider the CLB when making changes to their design, hardware or procedures, end (111) report to the NRC all changes to their licensing basis. As discussed in the memorandum from the EDO to Commissioner Curtiss forwarding this response, the staff has concluded that the findings of the audit do not raise significant safety concerns for operating reactors. Nevertheless, the audit results and the CLB workshop discussions

lead the staff to question the adequacy of the NRC's regulatory practices with respect to clearly identifying: (1) which NRC requirements and licensee commitments constitute new design bases, and which new commitments and requirements are not considered to be design bases but nonetheless form part of the plant's licensing basis, (11) the recordkeeping and reporting requirements with respect to licensing basis information, end (11i) the change process applicable to licensing basis information. These questions relate to the long-term control of the CLIP to assure the underlying safety interests of the CLB are maintained.

Neither the audit findings of the staff nor the discussions at the CLB workshop identified any specific safety concerns warranting immediate action. However, deficiencies were identified that warrant further evaluation and actions to assure that the regulatory process and licensees' programs are adequate to maintain the CLB and assure corpulence with ill portions of the CLB. The staff plans to resolve the uncertainties concerning control of the CLB and to develop any needed regulations within the framework of 10 CFR Part 50. Amendments of present Part 50 regulations end staff interpretations to add definitions, eliminate ambiguities in existing definitions, and to tighten requirements for controlling and documenting changes to the CLB and to plant design and procedures way be necessary. Dealing with this issue for currently-operating reactors will assure that the first principle of the license renewal rule is preserved.

2. Question

If this basic principle of 10 CFR Part 54 remains valid today, notwithstanding the findings set forth in SECY 92-314, why is there a need for any further action along the lines of what the staff has recommended in this SECY paper to improve the existing regulatory process (e g , to define CLB for operating reactors, to clarify the process for changes to the CLB, to clarify the definition of the terms "commitment" and “design bases” as those terms are used in the CLB, and to establish a process that will ensure that licensee changes to any commitments are reflected on the docket)? If, on the other hand, the staff believes that further steps are required to improve the regulatory process to address the shortcomings identified in SECY 92-314 in our approach to CLB, along the lines of the steps recommended in this SECY paper, how does one escape the conclusion that the regulatory process as it relates to main ruining an adequate CLB appears not to be adequate at the current time?

Answer

During the FSAR audits and the CLB workshop, the staff found certain process weaknesses at the audited facilities that could allow changes to be made without ~ licensee review to assess the impact on docketed CLB commitments In SECY 92-314, the staff proposed to conduct an evaluation to determine if the existing requirements and guidance should be revised Once the evaluation is complete, the staff can better determine whether to further clarify existing regulations, issue new regulations or guidance or take action to ensure implementation of existing requirements. These

actions are examples of the NRC a regulatory process that routinely finds and corrects weaknesses in the regulatory fabric and that forms the basis for the basic principles underlying 10 CFR 58.54.

3. Question

Please provide some perspective on the safety significance of the staff s findings and the priority and schedule for the actions that the staff has proposed to address the matters raised in the subject SECY paper.

Answer

No specific safety concerns warranting immediate action were identified during the limited audits performed by the staff. In conducting the audits the staff noted possible weaknesses in the processes some licensees used to ensure that design changes procedural modifications and safety evaluations are being evaluated against docketed commitments.

The staff expects the scoping evaluation to take approximately 8 to 10 months. If rule changes appear warranted the change would take about 2 more years.

4. Question

To the extent that the remedial steps that the staff proposes to take would constitute backfits, how will the NRC show that such actions will result in ·"a substantial increase in the overall protection of the public health and safety" and that the ·"direct and indirect costs of implementation...are justified in view of this increased protection" (10 CFR 50.109 (a)(3))?[2]

Answer

The staff cannot yet determine which actions, if any, will be required beyond the evaluation discussed in SECT 92-314. The staff will evaluate any proposals for either additional action or regulatory changes when it conducts its evaluation, in which it will compare various alternatives for action, and determine whether such actions are justified under the Backfit Rule. The decision to take additional action will depend, in part, on the results of the evaluation and the safety significance of any possible problem areas found. The backfit analysis of 10 CFR 50.109(a)3 will not he required if the staff concludes that actions are necessary to achieve compliance with existing requirements.

[2] If it is the staff's intention to treat this question as a 'compliance' issue, please be specific about the requirements in our current regulations that the staff believes are not presently being met by licensees.

5. Question

With regard to the staff's proposal to initiate rulemaking to provide a definition of the CLB for operating rectors why isn't the definition of CLB that is contained in 10 CFR 54.3 which in turn is based upon our experience with operating reactors, sufficient What is the rationale for having a separate CLB definition in Part 50?

Answer

The staff believes that the definition of CLB in 10 CFR 54.3 is a sufficient definition of licensing basis' for 10 CFR Part 50. The staff will evaluate the advantages and disadvantages gas of adding this definition to 10 CPR Part 50. It is noted that the November 30 1992 OPP Report 92-02 raises further questions about the appropriate definition of CLB.

6. Question

To what extent if at all, would the problems that the staff has identified in SECY 92-314 be corrected by simply requiring that the CLB be compiled?

Answer

The audits found that licensees can access the documents containing the CLB Compiling the CLB would have little positive effect on the process weaknesses identified in SECY 92-314.

7. Question

Does the staff consider undocketed, detailed design basis documentation maintained by licensees to be a part of the CLB? If so, is this consistent with the definition of CLB in Part 54?

Answer

The staff's view is that “undocketed" information is not considered to be part of the CLB The term design basis documentation' has been discussed in SECT 91-364 dated November 21, 1991, and in NUREG-1397 on "An Assessment of Design Control Practices and Design Reconstitution Programs in the Nuclear Industry Due to the confusion in the industry over this term, the staff defined 'engineering design bases" to include both (I) the design bases as defined by 10 CFR 50.2, Which is part of the CLB, and (2) other design considerations implemented to optimize the system design for operation, maintenance, procurement, installation, or construction.

8. Question

SECY 92-314 points to the apparent lack of a clear and uniform "understanding of the term design basis, noting that this term has been employed in a number of different contexts to mean different things. In this regard:

(a) What are the technical end legal ramifications of reinterpreting the definition of design basis" to encompass a broader range of design features than those specifically related to design basis accidents and transients?

(b) What are the advantages and disadvantages of broadening the interpretation of the term “design basis" to include all aspects of facility designs mandated by regulation?

(c) What are the advantages and disadvantages of broadening the interpretation of the term “design basis" to include all aspects of the design contained in the CLB?

Answer

(a) In SECY 92-314 the staff stated it found differences among the licensees in interpreting the term “design bases". Some of the questions raised by industry at the CLB workshop were related to scope; however, most were related to depth.

The staff has not expanded its interpretation of “design bases” as that term is used in 10 CFR 50 2. This term has not been limited solely to design basis accident and transients However, over the years, many of the discussions have focused on design aspects to cope with design basis accidents end transients and in these discussions the term design basis" has been limited in context to refer to the conditions associated with design basis accidents and transients. Nevertheless, the term as used in 50.2 refers to a wider range of structures, systems, components and functions than those necessary to cape with design basis accidents and transients.

In connection with the design basis reconstitution program, the staff has utilized the term “design bases" to include a broader range of design features than those specifically related to the design bases accidents and transients discussed in the FSAR when the operating license was issued (e.g. ATWS, Station Blackout). The scope of the design bases has been interpreted by the staff to encompass all of the functions performed by the structures, systems and components at the facility. Exceptions to this general rule include the requirements in 10 CFR 50 47 for emergency facilities and equipment and the requirements in 10 CFR 73.55 for safeguards facilities and equipment.

Although broad in scope, the term “design bases" is limited in depth of detail to docketed information and commitments made by licensees to identify the specific functions to be performed by the structures, systems and components of the facility

and limiting values for controlling parameters as reference bounds for the design of plant features.

From a legal standpoint, if the staff were to reinterpret a specific application of the “design bases" to encompass additional functions to be performed by a structure, system or component of the design, and the matter involved a change or effect covered by 10 CFR 50 71(e), the broadened scope of the interpretation of “design bases” could potentially result in a broadening of the design aspects or of the structures, systems or components included in the UFSAR and covered by 10 CFR 50.59. As discussed in the memorandum from the EDO to Commissioner Curtiss forwarding this response, the FSAR update requirements contained 1r 10 CFR 50 71(e) have not been interpreted to require that newly developed design bases as a result of generic letters, bulletins, and other sources be included in the FSAR. While 10 CFR 50.59 allows, among other things, certain changes to the facility as described in the FSAR without prier NRC approval, it does not provide a process that explicitly covers the design bases which are on the docket but not in the FSAR.

In license renewal under Part 54, the functions of the structures, systems and components important to licensee renewals are set forth in IQ CFR Part 54. Thus, a staff broadening of the term "design bases” would not directly affect the structures, systems and components covered by 10 CFR 54.3. However, if the staff should interpret what is required to accomplish the functions specified in 10 CFR 54 3 more broadly than previously, this could have the effect of broadening the scope of structures, systems or components covered by 10 CFR 54 3.

The staff's follow-up actions in SECY 92-314 are directed toward clarifying the definitions, processes, regulatory guidance and requirements to ensure that the FSAR, design bases documentation, docket and plant records are complete end the processes for maintaining and churning the design bases and other components of the CLB are clear.

(b) The staff's approach to design bases as discussed in (a) above is broad based and includes .11 functions of the facility design features mandated by the regulations within the definition of the design bases with the exception of the emergency facilities and equipment and safeguards facilities and equipment. The requirements of 10 CFR 50 54(p) and (q) provide for maintenance and change of the associated CLB in these areas. While there May be some advantage to expanding the definition of the design bases to include these features, such as allowing for a more inclusive set of administrative requirements to govern the process for evaluating the acceptability of and reporting design changes to the NRC, the current requirements for controlling the CLB for emergency facilities and equipment and safeguards facilities and equipment are adequate.

(c) As discussed in (a) above, the staff's interpretation of the term "design bases" is broad in scope but limited in depth of detail to docketed information and docketed commitments made by licensees to address the functions and limiting values for the design of plant features. Additional docketed details related to the design may be part of the CLB, but are not considered design bases. Expanding the definition of "design bases" to include this additional detail, in conjunction with other process changes (e.g. 10 CFR 50.59, Appendix B to 10 CFR Part 50) might provide a more inclusive and consistent approach for controlling and reporting changes to the design; however, such an approach may be overly conservative and burdensome.

List of Plants Audited and Issues Reviewed

PLANTS AUDITED

Site	Dates Audited	Region	NSSS	OL Issuance
Hope Creek	March 8-12	I	GE	1986
Crystal River	March 29 - April 2	II	B&W	1977
Fort Calhoun	April 19-23	IV	CE	1973
Braidwood	May 10-14	III	W	1987 & 1988
Davis-Besse	May 17-21	III	B&W	1977
Beaver Valley	June 7-11	I	W	1976 & 1987
McGuire	June 7-11	II	W	1981 & 1983

ISSUES REVIEWED

10 CFR 50.62	Anticipated Transients Without Scram (ATWS)
Generic Letter 89-13	Service Water System Problems Affecting Safety Related Equipment
Generic Letter 88-14	Instrument Air System Problems Affecting Safety-Related Equipment
NUREG-0737, 1. C . 5	Procedures for Feedback of Operating Experience to Plant Staff
Bulletin 85-01 (PWRs)	Steam Binding of Auxiliary Feedwater Pumps
Bulletin 87-01 (BWRs)	Power Oscillations in Boiling Water Reactors

Assorted Licensee Event Reports (between 6 to 10 LERs per plant)

Assorted Notices of Violation (between 3 to 6 NOVs per plant)

The licensee's Design Basis Reconstitution or Documentation Program

ENCLOSURE 3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

Docket No. 50-354

Mr. Steven E. Miltenberger
Vice President and Chief Nuclear Officer
Public Service Electric and Gas Company
Post Office Box 236
Hancocks Bridge, New Jersey 08038

Dear Mr. Miltenberger:

August 23, 1993

SUBJECT: SPECIAL AUDIT OF CONTROL PROCESSES FOR COMMITMENTS THAT AFFECT THE CURRENT LICENSING BASIS, HOPE CREEK GENE M TINS STATION (TAC NO. M85807)

This letter provides the results of the commitment management audit conducted by the Office of Nuclear Reactor Regulation at the Hope Creek Generating Station, on March 8-12, 1993. As you are aware, the staff is conducting audits at a cross-section of reactor plants to assess the processes used by licensees for controlling commitments that affect the plant's current licensing basis. The staff will use the information gathered during the audits to evaluate the regulatory process in this area. Hope Creek was the first site visited by the staff, and our audit report is enclosed.

The audit team focused on three principal areas: (1) management of commitments made to the U.S. Nuclear Regulatory Commission (NRC), (2) reporting of changes to commitments made to the NRC, and (3) maintaining and updating the final safety analysis report (FSAR). In addition to reviewing the governing programs for these areas, the team reviewed the status of commitments made to the NRC in response to specific issues (selected generic letters, bulletins, licensee event reports, and notices of violation) in order to examine the programs in actual practice.

Overall, the team found that commitments affecting the plants current licensing basis were being implemented and maintained. The team also found that the programs for managing and reporting commitments controlled the reporting of changes to commitments to the NRC. Finally, the team found that the commitments it reviewed that affected the plant updated FSAR (UFSAR) were captured by the UFSAR update process. The team did not identify any items of significance in its review of commitments made in response to the specific issues.

The team thanks the plant staff for its candor in our discussions and its cooperation in providing the team the information necessary to conduct an efficient audit. If you have any questions or comments concerning this report, please contact me or Eric Leeds at (301) 504-1133.

Sincerely,

/s/

Michael J. Davis, Acting Project Manager
Project Directorate I-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosure:
Audit report

cc w/enclosure:
See next page

DISTRIBUTION

Docket File	MDavis
NRC & Local PDRs	MO'Brien
PDI-2 Reading	SNewberry
SVarga	ELeeds
JCalvo	EWenzinger, RGN-I
M Boyle	JWhite, RGN-I

OFFICE	PDI-2.1.A	PDI-2/PM	PDI-2/D
NAME	MO'Brien	MDavis:rb	MBoyle
DATE	8/23/93	8/23/93	8/23/93

OFFICIAL RECORD COPY
DOCUMENT NAME: HC85807.GEN

The team thanks the plant staff for its candor in our discussions and its cooperation in providing the team the information necessary to conduct an efficient audit. If you have any questions or comments concerning this report, please contact me or Eric Leeds at (301) 504-1133.

Sincerely,

/s/

Michael J. Davis, Acting Project Manager
Project Directorate I-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosure:
Audit report

cc w/enclosure:
See next page

cc:

M.J. Wetterhahn, Esquire
Winston & Strawn
1400 Street, N.W.
Washington, DC 20005-3502

R. Fryling, Jr., Esquire
Law Department - Tower SE
80 Park Place
Newark, New Jersey 07101

Hope Creek Resident Inspector
U.S. Nuclear Regulatory Commission
Drawer I
Hancocks Bridge, New Jersey 08038

Mr. J. Hagan
Vice President - Nuclear Operations
Nuclear Department P.O. Box 236
Hancocks Bridge, New Jersey 08038

Mr. R. Hovey
General Manager - Hope Creek Operations
Hope Creek Generating Station P.O. Box 236
Hancocks Bridge, New Jersey 08038

Mr. Frank X. Thomson, Jr., Manager
Licensing and Regulation
Nuclear Department P.O. Box 236
Hancocks Bridge, New Jersey 08038

Regional Administrator, Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, Pennsylvania 19406

Dr. Jill Lipoti, Asst. Director
Radiation Protection Programs
NJ Department of Environmental
Protection and Energy CN 415
Trenton, New Jersey 08625-0415

Mr. J. A. Isabella
MGR. - Generation Department
Atlantic Electric Company
Post Office Box 1500
;199 Black Horse Pike
Pleasantville, New Jersey 08232

Richard Hartung
Electric Service Evaluation
Board of Regulatory Commissioners
2 Gateway Center, Tenth Floor
Newark, NJ 07102

Lower Alloways Creek Township
c/o Mary 0. Henderson, Clerk
Municipal Building, P.O. Box 157
Hancocks Bridge, NJ 08038

ENCLOSURE

COMMITMENT MANAGEMENT AUDIT OF THE

HOPE CREEK GENERATING STATION

MARCH 8-12. 1993

I. Scope and Participants

The purpose of the audit conducted at Hope Creek was to assess the licensee's programs for identifying and controlling commitments that affect the facility's current licensing basis. The audit focused on three principal areas: (1) management of commitments made to the U.S. Nuclear Regulatory Commission (NRC), (2) reporting of changes to commitments made to the NRC, and (3) maintaining and updating the final safety analysis report (FSAR). The team reviewed the licensee's administrative procedures involving commitment management; reporting; action tracking; control of design, configuration, test and experiments; and others. To examine the programs in actual practice, the team reviewed the status of commitments made by the licensee to the NRC in response to specific issues. Five of these issues, generic in nature, were the following:

10 CFR 50.62	Anticipated Transient Without Scram (ATWS)
Generic Letter 89-13	Service Water System Problems Affecting Safety-Related Equipment
Generic Letter 88-14	Instrument Air System Problems Affecting Safety-Related Equipment
Bulletin 88-07	Power Oscillations at Boiling Water Reactors
NUREG-0737, I.C.5	Procedures for Feedback of Operating Experience to Plant Staff

The remaining issues were specific to Hope Creek, involving licensee commitments made in licensee event reports (LERs) and responses to notices of violation (NOVs). The team also reviewed the licensee's configuration baseline documentation (COD) program to determine how a commitment from the program would be captured in the commitment management process.

The team relied on standard NRC inspection practices in conducting the review of specific commitments. In conducting the audit, the team performed system walkdowns, reviewed applicable documentation (including design change packages, training records, and procedures), and interviewed plant staff. A detailed review for each issue specified above is contained in the appendix to this report.

The following NRC personnel participated in this audit:

Eric J. Leeds, Team Leader
Steven R. Stein
James E. Beall
Anthony J. D'Angelo

II. Findings and Conclusions

The following are the team's findings and conclusions for the three major areas of focus: (1) commitment management, (2) reporting changes to commitments made to the NRC, and (3) maintaining and updating the FSAR.

Commitment Management: Overall, the team found that commitments affecting the plant's current licensing basis were being implemented and maintained. No significant deficiencies were found in the identification, tracking, completion, or maintenance of licensee commitments involving design modifications, procedures, and programs. The licensee required annotating procedural steps that were added as the result of a commitment made to the NRC. The administrative control process for revising procedures prohibited removing annotated procedural steps without the concurrence of the licensing organization. This process provided assurance that revised procedures would include previous commitments. Although there was no defined process requiring the review of previous commitments for design modifications, the team did not identify any examples in which a committed modification was inadvertently altered by a subsequent modification. The team attributed this to the experience level of the engineering organization and the multiple levels of review and approval required by the design change process.

Reporting Changes to Commitments Made to the NRC: The licensee's programs for managing and reporting commitments controlled the reporting of changes to commitments to the NRC. The programs differentiated between: (1) changes to regulatory requirements that require NRC approval before implementation, such as the license and technical specifications; (2) changes to commitments that the licensee requires its staff to notify the NRC (even if the NRC has no formal reporting requirements), such as the updated final safety analysis report (UFSAR), LERs, and responses to generic letters, bulletins, and notices of violations and deviations; and (3) changes to commitments that do not require NRC approval or formal notification, such as internal responses to information notices. The team found two instances in which changes to commitments previously made to the NRC were not formally documented in docketed correspondence by the licensee. In one case, the licensee had discussed the change with the resident inspector. In the other case, the licensee had not informed the NRC of the change. However, the change was of a minor nature. Details of both cases are discussed in the body and the appendix of the report.

Changes Made to the Updated Final Safety Analysis Report: The commitments the team reviewed that affected the plant UFSAR were captured by the licensee's UFSAR update process. The team reviewed eight design changes to the redundant reactivity control system (RRCS), an ATWS system, and eight LERs in which the licensee had committed to make a plant change. In all cases, the design changes that affected the UFSAR were captured in the UFSAR update process.

III. Discussion

A. Commitment Management

The team found that commitments affecting the plant's current licensing basis were being implemented and maintained. In its review of licensee commitments to specific issues, the team found no significant deficiencies in identifying, tracking, completing, and maintaining licensee commitments in design modifications, procedures, and programs. The licensee required annotating procedural steps that were added as the result of a commitment made to the NRC. The administrative control process for revising procedures prohibited removing annotated procedural steps without the concurrence of the licensing organization. This process provided assurance that revised procedures would include previous commitments.

The licensee maintained a computerized action tracking system (ATS) that effectively displayed pending and completed items, including commitments. Other programs, such as the CBD program, contained mechanisms to screen items for inclusion in the ATS as commitments. Although there was no defined process requiring the review of previous commitments for design modifications, the team did not identify any examples in which a committed modification was inadvertently altered by a subsequent modification. The team attributed this to the experience level of the engineering organization and the multiple levels of review and approval required by the design change process.

The licensee's commitment management program, as described in Procedure NC.NA-AP-ZZ-0030, prescribed assigning a commitment management number (CMN) to long-term commitments. Long-term commitments were those requiring a recurring or continuous activity, a plant modification, or a procedure change to satisfy the commitment. The program required the CMN to be annotated in the documents that implement the commitment. The licensee used some discretion in assigning CMNs and might assign one to a one-time commitment as a means of providing additional control.

The licensee defined commitment as "a Written or verbal] statement calling for action in response to a regulation, finding, or recommendation." In Procedure NC.NA-AP.ZZ-0035, "Nuclear Licensing and Reporting," the licensee included as commitments responses to generic letters, bulletins, notices of violations and deviations, and inspection report follow-up items; licensee event reports; the UFSAR; and internal responses to information notices, Institute of Nuclear Power Operations (INPO) findings and significant operating event reports (SOERs), quality assurance corrective actions, and NRC observations and suggestions. During the review of the specific issues, there were no instances of disagreement between the team and the licensee involving the identification, interpretation, or intent of any commitment. The team concluded that the licensees definition was adequate to capture the pertinent information and identify this information as commitments.

B. Reporting Changes to Commitments Made to the NRC

The licensee's programs for managing and reporting commitments controlled the reporting of changes to the NRC. The programs differentiated between (1) changes to regulatory requirements that require NRC approval before implementation, such as the license and technical specifications; (2) changes to commitments that the licensee requires its staff to notify the NRC (even if the NRC has no formal reporting requirements), such as the UFSAR, licensee event reports, and responses to generic letters, bulletins, and notices of violations and deviations; and (3) changes to commitments that do not require NRC approval or formal notification, such as internal responses to information notices, INPO findings, and NRC or INPO observations and suggestions. The programs allowed managers to use judgment in deciding if changes to commitments that do not require NRC approval or formal notification are discussed with the NRC. The programs required such discussion if the manager had reason to believe the NRC was aware of the commitment's implementation.

The team found two instances in which changes to commitments previously made to the NRC were not formally documented by the licensee in docketed correspondence. The changed commitments were (1) returning to the original wording in a procedure that had been changed in response to NOV 89-80-01 and (2) not meeting the schedule for instrument air system testing committed to in

LER 89-17. The NRC was not informed of the procedure change that reversed the change made as a commitment in response to NOV 89-80-01, although the licensee's program required such notification. Although the NRC was not informed of the change, the audit team found that the change was of limited significance. Regarding LER 89-17, the licensee had discussed the missed testing schedule with the NRC resident inspector when the licensee discovered it, although the program required a revised LER for a change in commitments made in an LER. However, the delayed testing was an existing test developed in response to Generic Letter 88-14 and only referenced in the LER as being scheduled for completion during the 1988 refueling outage. The testing was completed during the next refueling outage.

The licensee provided the audit team an example of an NRC notification for an issue that was not part of the audit team's review, but that exemplified how the licensee's notifications were sensitive to the significance of the issues. During plant licensing, the licensee had committed in its UFSAR to remove power from selected solenoid-actuated valves in response to Generic Letter 81-12, "Fire Protection Rule." The licensee subsequently determined through analysis that the affected systems were within acceptable design parameters and, through its 10 CFR 50.59 review process, that the change did not represent an unreviewed safety question. Although prior notification of the NRC was not required (per 10 CFR 50.59), the licensee officially notified the NRC of the change by letter, because the issue had been considered significant during the licensing process.

C. Maintaining and Updating the FSAR

The licensee's control of the UFSAR updates and figure changes ensured that plant modifications were captured and incorporated in the UFSAR. The Hope Creek site procedure for controlling plant design and configuration changes and experiments that would cause a modification to the physical plant or effect a change to a plant document (such as plant drawings or equipment specifications) required the originator of the change to complete a document change request, and this process included changes to the UFSAR.

Before a physical change was made to the facility, the licensee conducted a review for 10 CFR 50.59 applicability. It was during this review that the licensee identified the documents that would be affected by the proposed plant change. The team reviewed eight design changes to the RRCS, an ATWS system, and eight LERs in which the licensee had committed to make a plant change. In all cases, the design changes that affected the UFSAR were captured in the UFSAR update process.

The team found that the 10 CFR 50.59 review packages were of sufficient detail and depth and concluded that the control of UFSAR changes would ensure that the UFSAR accurately reflected changes made to the plant design. The 10 CFR 50.53 packages reviewed were of such detail that the specific section numbers and titles of paragraphs in the UFSAR, or other documents that were reviewed for 10 CFR 50.59 applicability (such as regulatory guides), were documented in the review package. In addition, many of the 10 CFR 50.59 packages contained, as excerpts, the specific UFSAR paragraphs affected by the change.

APPENDIX - SPECIFIC ISSUES REVIEWED AT HOPE CREEK

To examine the implementation of the licensee's programs, the team reviewed the licensee's commitments to the following specific issues:

10 CFR 50.62	Anticipated Transient Without Scram
Generic Letter 89-13	Service Water System Problems Affecting Safety-Related Equipment
Generic Letter 88-14	Instrument Air System Problems Affecting Safety-Related Equipment
Bulletin 88-07	Power Oscillations at Boiling Water Reactors
NUREG-0737, 1. C .5	Procedures for Feedback of Operating Experience to Plant Staff
	Configuration Baseline Documentation Program
Notices of Violation (NOVs)	89-02-01 and 89-80-01
Licensee Event Reports (LERs)	87-23, 87-25, 87-46, 88-11, 88-16, 88-21, 88-28 89-17, and 89-21

10 CFR 50.62 Anticipated Transient Without Scram (ATWS)

The audit team reviewed eight changes made to the ATWS system since the system was initially approved by the NRC. The licensee implemented these design changes after reviewing them for 10 CFR 50.59 applicability. The team also selected for review eight LERs in which the licensee had committed to make some modification to the plant. All commitments made by the licensee to the NRC involving the ATWS system had been fulfilled.

The ATWS design changes included several changes to components in the system and one change to the logic for the starting criteria of the standby liquid control system. The changes were all reviewed for 10 CFR 50.S9 applicability (one required NRC approval because it was a change to the license). The 10 CFR 50.59 packages reviewed by the team typically contained two to three pages of excerpts from the UFSAR or other documents that may have affected the proposed change or have been affected by the proposed change and require updating. The team concluded that the review appeared to be detailed and accurately documented.

In accordance with its design change program, the licensee reviewed previously made commitments that may have affected the proposed design change during its 10 CFR 50.59 review process. The design change process was documented in Procedure NC.NA-AP.ZZ-0008(Q). The team determined that, although the procedure did not contain specific direction or a list of documents to be reviewed for commitments, individual engineers used the licensees computer-based systems to research applicable commitments.

Engineers used a number of computer-based systems to research past commitments that were documented in correspondence. These systems included the action tracking system and several text-retrieval systems that contain the majority of licensee correspondence with the NRC. The UFSAR was also placed on the text-retrieval system. The team interviewed several engineers who uniformly indicated that the text-retrieval systems were of great help in researching commitments and requirements during 10 CFR 50.59 reviews.

The team concluded that this review process appeared to work well, based on the status of commitments reviewed. The team also noted that the thoroughness of the review for past commitments depended on the technical expertise of the individual engineers performing the review.

The team identified a potential weakness in the licensee's design change program for commitments made in LERs and in response to NOVs. Design changes implemented to meet these commitments may not be identified during the 10 CFR 50.59 review for subsequent design changes. Licensee engineers routinely checked the UFSAR for commitments and requirements imposed on the facility, but might not necessarily check LERs or responses to NOVs in which the licensee committed to make a plant modification.

For example, the licensee had committed in LER 88-07, as the result of a reactor protection system actuation, to post signs on preamplifier panels cautioning personnel not to grind, weld, or cut in the vicinity of the panels. The signs were subsequently installed. However, plant design documents, such as the panel drawing or the equipment manual, were not changed to include the signs in the plant configuration. If any change were to be made to the panels, the engineer making the modification might not routinely check for commitments made in an LER or response to an NOV and discover the requirement for the signs. During a field walkdown, the team observed that one of four preamplifier panels did not have a sign. The licensee had no explanation for the missing sign. The licensee acknowledged the potential program weakness and indicated it would study possible program changes. The team noted that the safety significance of the missing sign was limited because three of the four signs were posted as committed to by the licensee.

<u>Generic Letter 89-13. "Service Water System Problems Affecting Safety-Related Equipment"</u>

The control and implementation of commitments at Hope Creek in response to Generic Letter 89-13 were complete and comprehensive. The licensee documented commitments to address Generic Letter 89-13 in letters of January 26, 1990, and December 10, 1992. The actions included hardware modifications, procedure changes, and periodic tests. The hardware modification packages were satisfactory and the components were confirmed to be installed in the plant. The new and revised procedures were adequate and clearly identified the commitments being fulfilled. The periodic tests satisfied the commitments and identified the attributes that were intended to meet the Generic Letter 89-13 commitments. The work order database for receiving tasks included information linking the jobs to the generic letter (and associated commitments).

Generic Letter 88-14. Instrument Air System Problems Affecting Safety-Related Equipment”

The team reviewed the licensee's response to the generic letter, the UFSAR change notice addressing Generic Letter 88-14 issues, the latest revision of the associated UFSAR sections, work orders for system testing, and maintenance/surveillance schedules. The team walked down accessible portions of the instrument air system (IAS) and primary containment instrument gas system (PCIGS) to verify implementation of a design change referenced in the response. The staff reviewed the licensee's method for tracking all the actions associated with its response in the action tracking system (ATS).

The licensee's commitments included changes in air quality testing, testing for component failure positions, and design changes following the testing. All but one of the commitments had been implemented. The final commitment scheduled for implementation, a design change to several air dampers following the air system testing, was controlled by a design change package and was tracked in the ATS. The licensee had also included in its ATS, as an item to be completed, a final review for completion of all commitments to meet the generic letter requirements.

The team compared the current version of the UFSAR to the commitments made in response to the generic letter and the UFSAR change document issued as part of the generic letter actions. The changes were consistent or were addressed in subsequent UFSAR change documents. As part of its system walkdown, the team verified the replacement of compressor motors that were installed to increase the capacity of the IAS.

The team verified a commitment to change the frequency of certain air system testing through the automated preventive maintenance and surveillance work order system. The automated system correctly identified the new testing frequency. The system also noted that the testing was associated with a commitment and referenced a commitment management number, the associated UFSAR section, and the licensees response to Generic Letter 89-14. These associations would alert utility personnel, who might wish to change some aspect of the preventive maintenance testing, to possible ramifications.

The progress to completion for all of the Generic Letter 89-14 commitments was tracked in the ATS and none of the commitments had been changed since the licensee submitted its response to the generic letter.

NRC Bulletin 88-07, "Power Oscillations at Boiling Water Reactors." and Bulletin 88-07. Supplement I

In response to the bulletin and its supplement, the licensee committed to take actions recommended in the bulletin with respect to procedures, operator training, and review of applicable instrumentation for adequacy. The team reviewed the adequacy of the procedural changes. The licensee updated seven operating and three reactor engineering procedures with information from the bulletin. The team reviewed all 10 procedures and determined that the changes made by the licensee reflected recommendations from the bulletin and were adequate.

NUREG-0737. I.C.5. "Procedures for Feedback of Operating Experience to Plant Staff"

The licensee's commitments with regard to the requirements of item I.C.5 are contained in the plant UFSAR. The team reviewed these requirements, the licensee's commitments, and the implementation of the commitments. All commitments had been tracked and implemented.

The team reviewed the licensee's actions in response to a specific issue discussed in NRC information Notice 92-36, "Intersystem LOCA Outside Containment," to examine the licensee's implementation of its operating experience feedback program. The reliability and assessment organization had performed the initial review of the information notice, determined the need for further evaluation, and, after meeting with senior plant management, assigned actions to the probability risk assessment group and the training and operations departments. The responsible departments evaluated the information notice and responded to the probability risk assessment group as required by the licensee's process. Changes to the training program included classroom and simulator training on intersystem LOCAs and were implemented. The team determined that licensee personnel had reviewed the information notice in accordance with the licensee's program.

Configuration Baseline Documentation (CBD) Program

Each CBD for service water and related systems contained a section on applicable codes, standards, and regulatory documents, as well as a section on design basis. Historical design change requirements were included so that the design could be traced from the original to the current design. The open items list was part of the published CBD so that the nature and status of an item were readily available. The licensee had evaluated open items in accordance with Procedure NC.DE-AP.ZZ-0018(Q), Revision 3, "Engineering Discrepancy Control," using discrepancy evaluation forms (DEFs). Each DEF is reviewed for operability impact and also for classification as an incident report in accordance with Procedure NC.NA-AP.22-0006(Q), Incident Report/Reportable Event Program and Quality/Safety/Concerns Reporting System."

The licensee reviewed the incident reports for reportability, assigned any documented (e.g., in LERs) commitments a commitment management number, and entered commitments in the ATS. Therefore, commitments that resulted from CBDs were captured in existing programs and tracked to closure.

In summary, the team found that the CBD program was well structured and the implementing procedures were comprehensive so that commitments identified during the CBD process had a high assurance of being identified and incorporated into the licensee's commitment management program.

NOV 89-02-01 - Control of Temporary Jumpers

The NRC had issued an NOV for inadequate control of electrical jumpers installed for troubleshooting when the jumpers are requested by the plant's operating staff. The licensee had assigned a commitment management number to the corrective action (modifying the troubleshooting procedure for the instrumentation and control department) to which it had committed in its response to the NOV, and the commitment management number was referenced in the ATS. The procedure modification made by the licensee in response to the NOV and the associated commitment management number remained in the procedure after it was revised several times, although the wording of the procedure modification had been changed.

The team noted that, even though the NOV referenced only the instrumentation and control procedure, the licensee changed the other site troubleshooting procedures and identified in the procedures the changes to the commitment management number associated with the NOV.

NOV 89-80-01 - Eight Examples of Failure To Follow Procedures

The NOV from the NRC's maintenance team inspection included eight diverse examples of licensee work activities during which site procedures had not been followed. The audit team reviewed each corrective action in the licensee's response to the NOV through the ATS to final implementation in procedure changes, plant changes, or work practices.

The licensee had not assigned commitment management numbers to any of the commitments made in response to the NOV. It correlated in its ATS one corrective action (procedure changes to improve administrative control of the temporary plugging of floor drains) to an existing commitment management number issued for an earlier INPO significant operating event report (SOER) on the same topic. The audit team reviewed the file for the INPO SOER commitment and found that it contained a cross-reference to the NOV.

All the commitments were implemented consistent with the response to the NOV. However, the licensee informed the team of one commitment that had changed since it was implemented. The wording in Procedure NC.NA-AP.ZZ-0009, "Work Control Process," for requiring an equipment tag to be hung at a component associated with a work request had been changed to satisfy one of the NOV items and had since been changed back to its original wording. "Shall" hang a tag had originally been changed to "should" hang a tag because of the NOV. In subsequent revisions of the procedure, the wording had been changed back to "shall” hang a tag.

The licensee's program, described in Procedure NC.NA-AP.ZZ-0035, "Nuclear Licensing and Reporting," required notification of the NRC when a commitment made in response to an NOV is changed. Although no notification was made in the case of Procedure NC.NA-AP.ZZ-0009 (above), the team found that the change was of limited significance.

Licensee Event Reports

The team reviewed the commitments associated with corrective actions contained in the following nine LERs:

87-23 Technical Specification Violation - Emergency Diesel Generators B and C Starting Air Pressure Low Due to Technical Specification Inconsistency

87-25 Non-Conservative Liquid Effluent Sampling Frequency Due to Inconsistency Between Specification Requirements and Procedural Requirements

87-46 Primary Containment Isolation System (PCIS) Initiation When Swapping Reactor Protection System Bus Power Due to Lack of Indication - Design Deficiency

88-11 Discovery of Non-Seismically Qualified Instrumentation Tubing Installation on IE Instrument Racks - Personnel Error

88-16 Unanticipated PCIS Actuations and CREF initiation Caused by Momentary Power Losses - Equipment Failure

88-21 Discovery of Cracking in an FRVS Recirculation Fan Ductwork With a Second FRVS Fan Out of Service - Design Deficiency

88-28 Both CREF Units inoperable - Equipment Failure

89-17 Reactor Scram Caused by Failure of Soldered Scram Valve Pilot Airline - Installation Deficiency

89-21 Deviation From Electrical Separation Criteria Between Transient Monitoring Circuitry and Reactor Protection System Panel Circuitry Due to Inadequate Review of Design Change Package in 1986

The team found no significant deficiencies with respect to meeting and maintaining the commitments in the sampled LERs. In the case of one LER, some weaknesses were noted. In LER 89-17, the licensee committed to complete certain testing before startup from the then-current refueling outage, but noted after startup that not all testing had been done. The testing was completed during the next refueling outage. The cause of the mistake was that the LER commitments originated as recommendations in the first Hope Creek significant event response team report and, as such, were not entered into the ATS. The procedures were amended so that items in subsequent SERT reports were entered into the ATS and tracked.

Licensee practice and intent are not to notify the NRC formally of all changes to commitments, but rather to assess each change individually. Changes in intent or substance would lead to a revised LER submittal, but minor changes or schedule changes might only be reported by phone to the resident inspectors.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON. D.C. 20555

May 19, 1994

OFFICE OF THE
SECRETARY

MEMORANDUM TO: James M. Taylor
Executive Director for Operations

FROM: John C. Hoyle, Acting Secretary

SUBJECT: SECY-4-066 - EVALUATION OF ISSUES DISCUSSED IN SECY-92-314, "CURRENT LICENSING BASIS FOR OPERATING PLANTS"

In response to the recommendations of the Regulatory Review Group (RRG), the staff is planning to address many of the concerns raised in SECY-92-314 and by the Office of Policy Planning in SECY-94-003 and OPP—92 - 02. The Commission supports the staff's completion of the RRG plan and has approved all of the recommendations in this paper. The vote on each recommendation and individual comments are as follows:

1.a End the program that sought volunteers to compile their CLB.

The Commission (with all Commissioners agreeing) has approved this recommendation.

1.b Not require licensees to compile the CLB within a single document.

The Commission (with the Chairman and Commissioners Remick and de Planque agreeing) has approved this recommendation

Commissioner Rogers disapproved this item, believing that it would be beneficial to both licensees and the NRC if there was a well managed CLB that included, as a minimum, a set of cross references that identifies the various components of the CLB and the location of their respective documents.

1.c Not revise the interpretation of the FSAR update rule to include the entire CLB.

The Commission (with Commissioners Rogers, Remick, and

SECY NOTE: THIS SRM, SECY-94-066, SECY-92-314, THE OCTOBER 15, 1993 SRM, AND THE VOTE SHEETS OF ALL COMMISSIONERS WILL BE MADE PUBLICLY AVAILABLE 10 WORKING DAYS FROM THE DATE OF THIS SRM.

de Planque agreeing) has approved this recommendation.

The Chairman disapproved this recommendation because approval at this time would appear to foreclose this option, even though the staff may consider it as part of implementing the RRG plan.

2. Not adopt the recommendations forwarded in OPP-92-02.

The Commission (with all Commissioners agreeing) approved this recommendation.

3. Make this paper publicly available with SECY-92-314 and the October 15, 1993, SRM.

The Commission (with all Commissioners agreeing) approved this recommendation.

Additional comments:

Commissioner Remick urged the staff to ensure that guidance on what constitutes a commitment and the types of controls to be placed on changing commitments, now being carried out in response to the recommendations of the RRG, concentrate on improving the efficiency and not on increasing the restrictiveness of the commitment change process.

Commissioner Rogers stated that the RRG effort to address many of the concerns raised by the staff in SECY-92-314 and by OPP should be given the highest priority including: (1) the provision of additional guidance on what constitutes a commitment and the types of controls to be placed on changing commitments, (2) reconsideration of the CLB definition, and (3) reconsideration of the design basis definition, as appropriate.

cc: The Chairman
Commissioner Rogers
Commissioner Remick
Commissioner de Planque
OGC
OCA
OIG
Office Directors, Regions, ACRS, ACNW, ASLBP (via E-Mail)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

November 13, 1997

Mr. Gregory M. Rueger, Senior Vice President
and General Manager
Pacific Gas and Electric Company
Nuclear Power Generation, NB9
P. O. Box 770000
San Francisco, California 94177

SUBJECT: DIABLO CANYON UNITS 1 & 2, DESIGN INSPECTION (NRC INSPECTION REPORT NOS. 50-275/97-202 AND 50-323/97-202)

Dear Mr. Rueger:

From August 4 through September 11, 1997, the staff of the U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Reactor Regulation (NRR), Special Inspection Branch, performed a design inspection at your Diablo Canyon Facility. This inspection reviewed the design of the auxiliary salt water (ASW) and the containment heat removal systems. The containment heat removal system consisted of the containment spray (CS) system and containment fan cooler unit (CFCU) and their support systems. The purpose of the inspection was to evaluate the capability of the selected systems to perform the safety functions required by their design bases, the adherence of the systems to their design and licensing bases, and the consistency of the as-built configuration and system operations with the updated final safety analysis report (UFSAR).

The findings of the inspection were discussed during a public exit meeting on September 11, 1997, and are presented in the enclosed report. Overall, the team determined that the systems are capable of performing their safety functions. However, two issues identified may represent potential unreviewed safety questions and an additional NRC evaluation is ongoing. One issue involves the single failure design of the CCW, ASW, and the residual heat removal (RHR) systems. Because of the design of the electrical distribution system, these systems are operated with both trains cross-tied. The resultant single train systems are vulnerable to passive failure when cross-tied and to active failures when the trains are split. The second issue involves the availability of the containment spray function during containment recirculation.

Both issues were previously identified and evaluated by Pacific Gas and Electric Company (PG&E) staff. The evaluations resulted in compensatory administrative actions, which involved changing emergency operating procedures and assignment of manual functions to operating and emergency response staff.

Issues were identified with the current ASW pump testing method that results in pump and heat exchanger unavailability. PG&E staff are pursuing changes to the current test method to improve system availability. Additionally, the ASW system supply path from the demusseling line is credited in the UFSAR since the single ASW intake bay screen is not seismically qualified. However, this alternate supply line is not being maintained or tested. PG8E's response to Generic Letter 89-13, “Service Water System Problems Affecting Safety-Related Equipment” and its actions to implement the maintenance rule did not resolve this issue.

Some design calculation weaknesses were identified, although they did not affect the overall results of the calculations. They involved updating and control of calculations, and the use of

nonconservative assumptions. In addition, the team identified discrepancies and inconsistencies in the UFSAR, procedures, design criteria memorandum, calculations, drawings, and other documents.

Please provide a schedule, within 60 days, detailing your plans to complete the corrective actions for the open items listed in Appendix A to the enclosed report. This schedule will enable the NRC staff to plan for the reinspection and closeout of these items.

As with all NRC inspections, we expect that your staff will evaluate the applicability of the results and specific findings of this inspection to other systems and components throughout the plant. In addition, please evaluate the inspection findings, both specific and programmatic, against your response to NRC's request (October 9, 1996) for information pursuant to 10 CFR 50.54(f) regarding adequacy and availability of design bases information.

In accordance with 10 CFR 2.790(a), a copy of this letter and the enclosure will be placed in the NRC Public Document Room, where they will be made available to the public, unless you notify this office by telephone within 10 days of the date of this letter and submit a written application to withhold the information contained therein. Such application must be consistent with the requirements of 10 CFR 2.790(b)(1). Any enforcement action resulting from this inspection will be handled by NRC Region IV via separate correspondence. Should you have any questions concerning the enclosed inspection report, please contact the project manager, Mr. S. D. Bloom at (301) 415-1313, or the inspection team leader, Mr. M. W. Branch, at (301) 415-1279.

Sincerely,

/s/ Stuart A. Richards, Chief
Events Assessment, Generic Communications,
and Special Inspection Branch
Division of Reactor Program Management
Office of Nuclear Reactor Regulation

Docket Nos.: 50-275 and 50-323

Enclosure: Inspection Report 50-275/97-202
and 50-323/97-202

cc w/ enclosure: See next page

U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION

Docket No.:	50-275 and 50-323
License No.:	DPR-80; DPR-82
Report No.:	50-275/97-202 and 50-323/97-202
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Nuclear Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	August 4 - September 11, 1997
Inspectors:	Morris Branch, Team Leader, Special Inspection Branch A. Bizarra, Contractor* R. Jason, Contractor* L. Rogers, Contractor* M. Sanwarwalla, Contractor* K. Steele, Contractor* (* Contractors from Sargent and Lundy)
Approved by:	Donald P. Norkin, Section Chief Special Inspection Section Events Assessment, Generic Communications, and Special Inspection Branch Division of Reactor Program Management Office of Nuclear Reactor Regulation

Table of Contents

EXECUTIVE SUMMARY

From August 4 through September 11, 1997, the staff of the U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Reactor Regulation (NRR), Special Inspection Branch, conducted a design inspection at Diablo Canyon Power Plant (DCPP). The inspection team consisted of a team leader from NRR and five contractor engineers from Sargent and Lundy Corporation (S&L).

The purpose of the inspection was to evaluate the capability of the selected systems to perform the safety functions required by their design bases, the adherence of the systems to their design and licensing bases, and the consistency of the as-built configuration and system operations with the updated final safety analysis report (UFSAR). For the purpose of this inspection, the team selected the auxiliary salt water (ASW) and the containment cooling systems including both containment spray (CS) and containment fan cooler units (CFCU), on the basis of their importance in mitigating design-basis accidents (DBAs). In particular, the inspection focused on the safety functions of these systems and their interfaces with other systems.

For guidance in performing the inspection, the team followed the applicable engineering design and configuration control portions of Inspection Procedure (IP) 93801, “Safety System Functional Inspection" (SSFI). The team reviewed portions of the plant's UFSAR, design-basis documents, drawings, calculations, modification packages, surveillance procedures, and other documents pertaining to the selected systems.

Overall, the team determined that the systems are capable of performing their safety functions. However, two issues identified may involve potential unreviewed safety questions and the NRC needs to evaluate them further.

The first issue involved single failure design issues that affects the CCW, ASW, and RHR systems. Because of the design of the electrical distribution system, these mechanical systems are operated with both trains cross-tied. These systems are vulnerable to passive failure when they are cross-tied and to active failures when trains are split. The safety evaluation for changing emergency operating procedures (EOPs) to resolve LER 97-001 conditions did not consider the failure of these systems to meet single failure design criteria as a potential unreviewed safety question (USQ).

The second issue involved the availability of containment spray during containment recirculation. Because of a discovery in 1991 involving system heat load concerns under design basis (single failure) conditions, the EOPs were modified to prohibit use of the residual heat removal (RHR) containment recirculation spray system. The corrective actions in 1991 involved administrative controls, such as manual operator action and guidance from the technical support center, but the UFSAR and TS were not updated accordingly. Chapter 6 and section 3.1.8.16 of the UFSAR and TS 3.6.2.1 still discuss the containment spray function during containment recirculation. The licensee's safety evaluation (10 CFR 50.59), dated September 4, 1997, to support not requiring the ability to spray from the containment sump under design basis conditions, did not identify the need to change technical specifications (TS).

Issues were identified with the current ASW pump testing method that results in pump and heat exchanger unavailability. The licensee is changing their testing program to eliminate the need to make the heat exchanger or pump inoperable for testing.

The ASW system supply path from the demusseling line is credited in the UFSAR since the single ASW intake bay screen is not qualified. However, this alternate supply line is not being maintained or tested. Pacific Gas and Electric Company's (PG&E) response to Generic Letter 89-13, “Service Water System Problems Affecting Safety-Related Equipment" and its actions to implement the maintenance rule failed to resolve this issue.

Generally, calculations reviewed by the team were good. However, it was not always clear as to what calculations were current and relevant to existing plant design. Several calculational assumptions were not conservative, but the overall calculational results were not adversely affected. No maximum allowable sea water temperature had been previously calculated. This calculation is currently being developed to evaluate the possible effects of the “EI-Nino” weather condition, which increases the ocean temperature.

The UFSAR was revised in 1997 regarding commitments for the emergency diesel generator's (EDG) response to transient loading. Clarification is needed as to the capability of the EDG to satisfy Regulatory Guide 1.9 requirements regarding frequency response during loading.

Prior to the inspection, the PG&E staff performed their own review of documents associated with the systems being inspected. That review identified many issues and approximately 50 action requests (ARs) were written to document specific findings. It is important that the AR review of the specific finding considers generic applicability so that the licensee's efforts can realize the most benefit. Additionally, during the course of the inspection the licensee documented many of the team identified issues in their corrective action program.

DCPP staff took immediate remedial actions for issues identified by the team and no immediate operability concerns currently exist. However, further review by NRR staff of the potential USQs may result in additional needed actions. The DCPP and PG&E staffs are addressing long term actions for team and licensee identified issues through the corrective action process.

III. Engineering

E1. CONDUCT OF ENGINEERING

E1.1 Inspection Scope and Methodology

The purpose of this inspection was to evaluate the capability of the selected systems to perform safety functions required by their design bases, adherence to the design and licensing bases, and consistency of the as-built configuration with the updated final safety analysis report (UFSAR). The systems selected for inspection were Auxiliary Salt Water and Containment Heat Removal, which included the Containment Spray and Containment Fan Cooler systems. These systems were selected on the basis of their importance in mitigating design basis accidents at Diablo Canyon.

The inspection was performed in accordance with NRC Inspection Procedure 93801, "Safety System Functional Inspection." The engineering design and configuration control section of the procedure was the primary focus of the inspection.

The open items resulting from this inspection are included in Appendix A. The acronyms used in this report are listed in Appendix C.

E1.2 Auxiliary Salt Water System Design Review

E1.2.1 Mechanical

E1.2.1.1 Scope of Review

The team evaluated the capability of the auxiliary salt water (ASW) system to remove the required heat load from the plant through the component cooling water (CCW) system to the Ultimate Heat Sink (UHS), i.e., the ocean. To determine plant total heat load, the team reviewed the Westinghouse Containment Integrity Analysis for a Loss-of-Coolant-Accident (LOCA) and Main Steam Line Break (MSLB). The team also reviewed portions of the CCW system analysis that dealt with heat transfer from the Containment Fan Cooler Units (CFCUs), residual heat removal (RHR) heat exchangers and safety-related equipment lube-oil coolers. As described in UFSAR Section 9.2.7.1, the ASW and CCW systems are essentially considered a single heat removal system for the purpose of assessing the plant ability to perform design bases heat removal.

Plant design drawings, calculations, modification packages, UFSAR, the design criteria manual (DCM), technical specifications (TS), operating procedures (OP), maintenance and surveillance tests, selected NRC Bulletins and generic letters, and engineering evaluations associated with the system were reviewed.

E1.2.1.2 Findings

a. Overall System Design Capabilities and General Operating Practices

The team's review determined that the ASW system was capable of removing the plant heat load for plant normal, abnormal and accident conditions. However, the manner in which the system is currently operated is not the way it was originally designed. Discoveries by the licensee that questioned some of the original calculational assumption have resulted in two increases in CCW temperature which have impacted other system operations such as the RHR, CS, and ASW systems. At the conclusion of the inspection, the final analysis/calculations to document the most recent changes to the design bases temperature for the ASW and CCW systems were not available for review by the inspection team. Additionally, the effects of "El Nino" on the ocean temperature were being reviewed by the licensee since there was no upper ASW system temperature limit established in design basis documents.

The ASW and CCW systems at DCPP are currently configured to operate with both their trains tied together for all plant conditions unless otherwise determined by the Technical Support Center (TSC). The recently revised EOP 1.3 specifies that the trains should only be separated during long term post-LOCA recirculation in cases of a single passive failure in one train. For the purpose of determining the ASW and CCW system heat removal capability each train of the system was evaluated for heat load removal of the combined trains. Though this configuration provides flexibility, it also challenges the system design capability since a single failure in the ASW or CCW systems would require operator action to reduce heat loads to the capacity of a single train. This aspect of system operation was not considered in the original design. As stated in UFSAR Section 9.2.7 and DCM S-17B, Revision 04, the original intent of the ASW system design was to be able to operate the ASW system as two separate trains during long term post-LOCA recirculation.

b. History of Changes to Design Requirements for ASW/CCW Systems

Both the ASW and CCW systems were originally sized to remove the heat load based on the minimum acceptable number of safeguards equipment in operation, i.e., 3 CFCUs, 1 containment spray (CS) pump and 1 RHR heat exchanger, to maintain containment and reactor/fuel integrity. However, as described in the licensee's 1991 LER (1-91-018), with both trains tied together, the limiting condition for design of the CCW system should be based on maximum heat addition to the CCW train with the maximum amount of safeguards equipment in operation and minimum heat transfer to the ASW system. As described in the LER, if maximum heat was added to the CCW system, the CCW temperatures could increase from the original assumed 125°F to a one time peak of 132°F for a duration of 20 minutes during the LOCA injection phase. Administrative controls, which limit system heat loads, would then maintain CCW temperature at 120°F for the remainder of the event.

In 1995 the licensee discovered (LER 1-95-013) that although the CCW and ASW temperature analysis performed after the 1991 discovery assumed worst case heat inputs the analysis would be further impacted by changing the assumed fouling factor for the CFCUs, RHR, and the

CCW/ASW heat exchangers. Specifically, the licensee's analysis assumed that the CFCUs and RHR heat exchangers were fouled, which was nonconservative since actual testing indicated that they were essentially clean. Therefore, the heat input to the CCW system would be more than assumed. This discovery resulted in another CCW temperature increase, which impacted the ASW system heat input as well.

c. Determine Heat Removal Capability of the ASW System

The limiting condition for design of the ASW system is minimum ASW flow and maximum CCW flow through the CCW heat exchanger with maximum heat transfer from the CCW system to the ASW system.

The limiting heat loads differ for the accident type and the time period after the initiation of the event. For example, maximum safeguards equipment in operation and a single active failure of an ASW pump with only one CCW heat exchanger in operation was the worst case for a Main Steam Line Break (MSLB) and during the injection phase of a LOCA. However, during the LOCA recirculation phase, the limiting design condition was determined to be operation of all 5 CFCUs and both RHR heat exchangers with a limiting single active failure of a solid state protection system (SSPS).

ASW system temperature is controlled by TS 3/4.7.12 which requires that the second CCW heat exchanger be placed in operation when the ocean temperature exceeds 64°F. Flow requirements are verified through regular surveillance testing (see section E1.2.1.f). Because of the effects of "EL Nino" on ocean temperature, the team questioned the licensee as to maximum ocean temperature limits that would continue to allow safe operation. DCPP could not identify the maximum ocean temperature at which the plant could be operated with both CCW heat exchangers in operation to maintain CCW and ASW systems within their existing design limits. At the time of exit, DCPP was preparing a calculation to determine the maximum UHS temperature at which the plant could be operated, and this has been left as a follow-up item. This item is identified as IFI 50-275/97-202-01, Review of UHS Calculation.

The following analyses were reviewed by the team to ensure that the heat generated by the different accident scenarios could be transferred to the UHS by the CCW/ASW systems:

<u>Containment Analysis</u>

Westinghouse analyses WCAP-13907, "Analysis of Containment Response Following Loss-Of-Coolant Accidents for Diablo Canyon Units 1 and 2," 12/93

WCAP-13908, "Analysis of Containment Response Following Main Steamline Break Accidents for Diablo Canyon Units 1 and 2," 12/93

DCPP calculation M-938, "CCW Data Input for 1993 Containment Analysis Program (CAP)," Revision 02 dated 2/22/95

<u>CCW System Heat Transfer and Pressure Analysis</u>

Westinghouse analysis WCAP-14282, "Evaluation of Peak CCW Temperature Scenarios for Diablo Canyon Units 1&2," 3/95 (injection phase)

DCPP calculation M-910, "CCW post LOCA (recirculation phase) analysis," Revision 02 dated 2-10-97

Westinghouse letter PGE-96-503 to DCPP, Analysis for the CCW system with lower fouling factors for the RHR heat exchangers and the CFCUs coolers.

DCPP calculation M-305, "CCW Temperatures and Pressures for Operating Modes," Rev. 12 dated 7/8/97

ASW System Heat Transfer and Pressure Analysis

DCPP calculation M-784, "To Determine the Maximum System Pressures and Temperatures for Various Modes of Operation," Revision 01 dated 1/28/97

WCAP-12526, "Auxiliary Salt Water and Component Cooling Water Flow and Temperature Study for Diablo Canyon Units 1 and 2," 6/92

DCPP calculation 52.27.55.41, "Evaluate Effect on ASW Discharge Pipeline due to 155°F Discharge Temperature as a Result of Higher CCW Temperature during a Design Bases Accident," Revision 01 dated 11/6/96

E1.2.1.2.c.1 Containment Heat Transfer

The team determined that the energy/ heat added to the containment from a MSLB for Case 10A of the WCAP-13908 MSLB analysis exceeded the heat from a double ended hot leg break LOCA in the WCAP-13907 analysis. The CCW temperature transient analysis for the MSLB Case 10A would, therefore, envelop any CCW analysis for the LOCA injection phase. For the LOCA recirculation phase, the maximum heat was added to the containment from the reactor coolant pump suction break scenario.

In WCAP-14282, the containment structures and the containment shell were considered as heat sinks in the Westinghouse model for long term cooling. The team determined that during the MSLB/LOCA injection phase, the CCW return temperatures from the CCW heat exchanger reached the system peak design temperature of 132°F for a duration of about 20 minutes. Review of calculation M-910 showed that with only 1 ASW pump and 1 CCW heat exchanger in operation, and all CFCUs and both RHR heat exchangers in operation during the recirculation phase, the CCW system would overheat and exceed its design limits. EOP E 1.3 provided operator instructions to control the heat load on the CCW system during the recirculation phase. The procedure specified that at the start of containment recirculation with only 1 ASW pump and 1 CCW heat exchanger available, only 3 CFCUs and 1 RHR heat exchanger could be in operation.

The team's detailed review, with the assistance of a Westinghouse representative, of the LOCA and MSLB analysis, including calculational notes, determined that overall the bases of the input data (mainly constituted by PG&E calculation notes) for the containment integrity analyses were available, accessible and controlled. Notwithstanding, the team identified an error in calculation (193-DC) associated with CFCU start times which supported both LOCA and MSLB analyses and found that an uncompleted calculation (M-939 Revision 0) had been used in the MSLB analysis. Additionally, the RCS flow assumptions used by Westinghouse were not conservative. These

discrepancies were analyzed by PG&E during the inspection and proved not to have adversely impacted the accident analyses results. In conclusion, the inspection confirmed that the current containment integrity analyses demonstrate that the plant's response to a LOCA or a MSLB will remain within the plant's design safety limits.

E1.2.1.2.c.2 CCW System Heat Transfer

WCAP-14282 did not use conservative fouling factors for maximum heat transfer to the CCW system from both the CFCU coolers and the RHR heat exchangers. Performance tests on the RHR heat exchangers and the CFCUs coolers determined lower fouling factors than considered in the analysis for heat transfer to the CCW system. Additionally, CCW/ASW heat exchanger tube plugging was not considered in the heat transfer analysis even though tests have shown plugging from marine life (AR A0440748). The team's review of the new analysis, performed by Westinghouse (Ref. Westinghouse letter PGE-96-503 to DCPP), for the CCW system with lower fouling factors for the RHR heat exchangers and CFCUs coolers determined that for both MSLB and the LOCA injection phase, the CCW temperatures exceeded the 132°F maximum CCW design temperature. The CCW system maximum design temperature limits were revised by DCPP to a value of 140°F for 6 hours. The team's review of CCW calculation M-305 determined that a maximum CCW temperature of 240°F would be reached in the CCW return line from the RHR heat exchanger. This temperature is within the temperature limitation allowed by the ASME code for the class of piping. The team also reviewed DCPP safety evaluation, DCP M-49291, "Change Design Bases Temperature of CCW System," Revision 0 dated 4/25/97 to determine if DCPP had addressed the effect of the temperature change on all interfacing equipment. The team determined that the effect of the temperature change on all interfacing equipment and systems had been adequately addressed.

DCPP's response to not considering heat exchanger tube plugging in the above analysis was that a higher fouling factor than what was determined from performance tests had been considered in the heat transfer analysis for the CCW heat exchangers, and in addition the manufacturer's specification (PGE DC-663212-26-1) allowed a maximum of 2% tube plugging without affecting heat transfer area; therefore, further consideration of tube plugging would make the analysis overly conservative. The team determined that the plant was operating with some of the tubes plugged, and requested DCPP to provide information on how design control was maintained on tube plugging. The team reviewed the tube plugging map drawing DC-663212, Sheet 66 Revision 01 and DCPP procedure MP M-56.21, "Salt Water Heat Exchanger Tube and Tube Plugging," Revision 3A, to assess design control on the number of heat exchanger tubes to be plugged. Though the map drawing indicated that a maximum of 2% or 24 tubes could be plugged, the team could not identify in the procedure any controls or restrictions on the allowable number of tubes to be plugged to remain within CCW system design bases. The team did not consider that strict controls were in place to prevent more than 2% of tubes being plugged, or that engineering would evaluate CCW system design and plant operation if more than 2% of tubes were required to be plugged. AR A0443543 was initiated by DCPP to evaluate the CCW heat exchanger tube plugging procedure to add the limit on the maximum number of tubes to be plugged.

At the time of the inspection, WCAP-14282 was in revision to finalize the preliminary analysis done in PGE-96-503 and to also capture the history and the effect of the CCW system changes on all interfacing systems. Issue of the revised WCAP-14282 will also supersede/revise a number of calculations and design documentation including DCMs and the UFSAR. The changes

necessary to incorporate revised WCAP-14282 into design bases documentation is being tracked by DCPP under AR A0439116. Review of revised WCAP-14282, and closure of AR A0439116 is identified as IFI 50-275/97-201-02.

E1.2.1.2.c.3 ASW System Heat Transfer

The team's review of Westinghouse analysis WCAP-12526 determined that with only one CCW heat exchanger in operation, a minimum of 10,300 gpm ASW flow at a maximum ocean temperature of 64°F was required to maintain the CCW temperature within its above design limits. This ASW flow and temperature forms the design bases for the ASW system, and has been used in all Westinghouse's analyses.

The team's review of calculation M-784 determined that with an initial CCW supply temperature of 140°F and CCW heat exchanger fouling factor of 0.0002, the ASW system discharge temperature from the CCW heat exchanger could reach 149°F for the MSLB/LOCA injection phase. A review was performed of calculation 52.27.55.41. The review determined that for the encased portion of the piping, the radial growth/stress in the piping would cause the concrete to crack and relieve the stress, preventing any buckling of the pipe. The team considered this to be acceptable as the concrete in question performed no safety or seismic function and would not affect plant safety or operation of the ASW system.

d. Capability to Isolate ASW System Trains for Long Term Post-LOCA Cooling

The team reviewed the ability of the ASW system to be separated into two redundant trains for long term post-LOCA cooling as described in UFSAR section 9.2.7.2, and as was the intent of the original design. The team determined that the ASW system, in combination with CCW system, could withstand a single active failure during all phases of accident mitigation as long as the trains remained mechanically cross-tied. The ASW system is currently configured to operate with both trains tied together. DCPP EOP E-1.4, "Transfer to Hot Leg Recirculation," originally required separation of the ASW and the CCW systems into isolated trains approximately 10 1/2 hours after the LOCA. The EOP was revised as part of LER 97-001-00 corrective action and the trains are now separated during long term cooling based on a decision to be made by the TSC to separate the trains to be able to withstand a single passive failure in the fluid system. The team determined that this ASW system operation did not form the original bases for the ASW system design or licensing, and was a potential unreviewed safety question (USQ) that needed to be further evaluated by the NRC. This item is identified as URI 50-275/97-202-03, Determine if Current Approach to Single Failure Design Represents a USQ.

Typically, plants are designed where most of the mechanical systems have two trains to meet redundancy criteria, and normally with two electric buses all components of interfacing mechanical trains are powered from the same electrical train such that failure of one bus would remove the safety function provided by one train, but the other train would be available to perform the function. At DCPP there are three safety-related electrical buses, F,G and H. The components in the ASW, CCW, RHR and CFCUs are powered from a mix of these three buses such that a loss on one electrical bus could affect the systems from performing their safety functions. The team determined that a postulated loss of Bus F following completion of the post-LOCA long term system separation, results in the loss of CCW flow in one cooling loop (B) and the loss of ASW cooling flow in the other cooling loop (A) resulting in a complete loss of plant cooling. A postulated loss of power to Bus G results in the loss of ASW cooling flow to one loop (B) such that the RHR

heat exchanger on that loop is not cooled, and the other RHR loop (A) is not available as the RHR pump is powered from this bus resulting in a total loss of RHR function. Preliminary analysis performed by DCPP showed that the CCW system would exceed design limits within a short time (approximately about 4 minutes). The inability of the ASW and CCW system design to withstand a single active failure of an electrical bus after train separation was detected by DCPP on January 31, 1997 when LER 97-001-00 was issued. Emergency Operating Procedure (EOP) E-1.4, "Transfer to Hot Leg Recirculation," that allowed train separation approximately 10 1/2 hours after a LOCA was revised to no longer require immediate separation of the ASW and CCW systems into separate trains after the transfer to hot leg recirculation. The decision to separate was transferred to the Technical Support Center (TSC) where a decision would be made after an evaluation of plant conditions. When questioned by the team, the licensee could not provide any analysis to support their change to the single passive failure design (i.e., no longer separating the trains). Several scenarios could be postulated during the long term cooling period where no failure mode analysis or consequence assessment was available.

e. ASW Pump Net Positive Suction Head

The following calculations were reviewed:

- M-953, "Determine if Adequate NPSH is available for 1 pump supply 2 Heat Exchanger," Revision 01
- M-885, "To Determine ASW Pump Change in Flow when Switching ASW/CCW Configuration," Revision 02
- M-988, "To evaluate the effects of the new ASW bypass piping," Revision 03

The team reviewed calculations M-953, M-885, and M-988 to verify the available net positive suction head (NPSH) for the ASW pumps from the intake bay at various tide levels including the design case tsunami drawdown below sea level. The team did note that calculation M-953 contained several conservative assumptions, which in some cases indicated that cavitation may occur, under non design basis conditions. DCPP initiated AR A0440920 to revise calculation M-953 to reflect more realistic assumptions. The team concluded that for the ASW design flow, sufficient NPSH was available for the ASW pumps when taking suction from the intake bay for the case of 1 pump supplying 1 heat exchanger and 1 pump supplying 2 heat exchangers.

f. ASW System Flow Rate and Pump Surveillance Testing

The team reviewed the licensee's calculations for ASW system hydraulic resistance, effects of the new ASW bypass piping, pump surveillance testing, test procedures, and acceptance criteria to evaluate ASW system capability to provide the minimum design flow of 10,300 gpm when the ASW pump is aligned with the heat exchanger of the other train.

Calculations M-885, M-186, "Estimate the friction loss of the ASW system," Revision 04, and M-988, "To evaluate the effects of the new ASW bypass piping," Revision 03, determine the ASW system flow rates. Calculation M-186 determines the frictional losses in the ASW system due to piping, fittings and equipment. This frictional loss data was used as the basis for the flows determined in calculation M-885. The ASW system bypass piping modification has been completed for Unit 1, and is expected to be completed for Unit 2 at the next refueling outage. Calculation M-988 evaluates ASW system flow rates for both Units 1 &2. This calculation forms

the design basis for evaluating ASW system flow rates for Unit 1. However, until completion of Unit 2 bypass modifications, calculations M-885 and M-186 form the design bases for Unit 2. On completion of the Unit 2 bypass, both these calculations will need to be superseded or archived and M-988 will form the design bases for both units. AR A0439116 was initiated by DCPP to review and update ASW system flow calculations.

M- 885 calculated flows “with” and “without” siphon effect. M-988, however, calculates flows with siphon effect. After exiting the CCW heat exchanger (EL. 93'), the ASW system discharges to a lower elevation (EL. 72.1' for Unit 1 and 68.6' for Unit 2) and a siphon is created in the discharge lines. The team agreed with the full siphon effect assumed in M-988. The team's review of the calculation determined that the pumps have the necessary capacity to provide the minimum ASW system design flow of 10,300 gpm through the cross-tie at a UHS temperature of 64°F at the low-low tide level. The above analysis to establish limiting flows did not consider pump performance degradation. Therefore, additional analysis will be necessary if pump degradation is noted.

The ASW system's ability to provide the required minimum design flow is demonstrated through regular surveillance testing performed under STP M-26, "ASW System Flow Monitoring.” To demonstrate adequate flow under the most limiting condition, the test flow is corrected to account for a minimum tide level of -4.1', and heat exchanger differential pressure. The corrections used in the STP have been determined in M-988, and were verified by the inspection team. However, review of engineering evaluation procedure PEP M-229, "Evaluation to Allow Taking Credit for a Single Train ASW flow for a Specific Duration of Time for Maintenance/Operations Evolutions," for single train design bases capability (UFSAR Sec. 9.2.7.1) showed a different correction factor for tide level than determined in M-988. The correction factor used is conservative, even though it does not agree with the design bases. The team determined that PEP M-229 may not be needed after WCAP-14282 is revised. DCPP initiated AR A0443540 to track the review of PEP M-229 after the WCAP is revised.

As per the requirements of TS Bases Section 4.0.5, surveillance testing of the ASW pumps is performed under STP P-ASW-11, 12, 21, 22 (11 for pump 1-1, 12 for pump 1-2, etc.), "Routine Surveillance Test of Auxiliary Salt Water Pump.” The team reviewed the results of the routine surveillance test performed on July 24, 1997, on pump 1-1. The results indicated that the pumps were able to deliver 12,116 gpm at a discharge pressure of 50.542 psig or about 117 feet which lies on the original pump performance curve. The team witnessed the surveillance test performed on pump 2-2 on August 14, 1997. The pump was able to deliver 11,730 gpm at a discharge pressure of 51.876 psig or about 119 feet, which also lies on the original pump performance curve. The latest pump tests showed minimal degradation of the pump performance since its installation. The ASW pumps are tested to a specific point on the pump performance curve to establish the acceptance criteria. The specific point selected for the test requires throttling of the CCW heat exchanger ASW outlet valve of the opposite train (the pump is tested through the cross-tie to demonstrate adequate performance for the most limiting condition) to meet configuration requirements for the test. If the surveillance test is being performed as post maintenance testing (PMT), it could result in both the ASW pump and the opposite heat exchanger being inoperable at the same time (the heat exchanger is declared inoperable when its outlet valve is throttled). The team considered that rendering the CCW heat exchanger inoperable by throttling of the ASW outlet valve every time the surveillance test was performed was an undesirable practice, and that test modifications would correct this problem. DCPP initiated AR A0443221 to either (1) obtain relief from Section Xl to allow testing the pump at various flow

rates or (2) re-baseline the test reference flow rate to a higher value so that the heat exchanger outlet valve does not need to be throttled from its normal position. The final resolution of this item is identified as IFI 50-275/97-202-04, Modification to ASW Pump Test Method.

g. Piping Design Pressure and Temperature

The team reviewed the ASW system piping schematic 102017 sheets 3 and 3B, Revision 83, DCM S-17B, DCM M-46, "Piping Pressures, Temperatures, and Operating Modes," Revision 23, and calculation M-784 to verify the piping design pressure and temperature classification for the discharge lines from the pump to the CCW heat exchanger and from the CCW heat exchanger to the ocean. The team determined that the pressure and temperature classification as determined in M-784 were acceptable. However the temperature classification in DCM S-17B did not reflect the classification in M-784. DCPP initiated AR 0438253 to revise DCM S-17B to reflect the classification in M-784. This discrepancy in design information is identified as example 1 of
URI 50-275/97-202-05, Discrepancy in Design Documentation.

DCM M-46 was revised under AT-DCMC AR A0417076 to address the revised discharge temperatures of 155°F short term and 145°F long term during post-LOCA recirculation at the exit of the CCW heat exchangers. The team identified that the new bypass line was not designed for demusseling, though this operating mode was still indicated in
DCM M-46. Deletion of ASW demusseling mode from all plant documents is being tracked by DCPP under AR A0431283.

h. Intake Structure

The team reviewed the intake structure to verify its design to support the safety function of the ASW pumps and associated piping and valves during a seismic event. The team determined that the ASW system was adequately supported and protected from external missiles to enable it to perform its function, except for the following:

- The ASW pumps for each unit have separate bays from which they take suction. As per UFSAR Section 9.2.7.2.3, "Each unit's pair of ASW pumps share a common traveling screen to remove floating debris from the incoming seawater. If the common screen for a unit becomes clogged with debris, seawater may be valved to the ASW pump bays from the unit's circulating water pump bays." The traveling screens at DCPP are designed as Class II, and are, therefore, neither seismically qualified or supported. The team determined that there is a potential for the screen to fail during a seismic event and restrict flow to the ASW pumps. The demusseling line flowpath is not tested or maintained on a routine basis to demonstrate its availability as an alternate flow path. The valves in the flowpath, however, are exercised to demonstrate their operability. The team identified that the inability to demonstrate an acceptable flowpath for ASW pump suction did not conform to the recommendation contained in GL 89-13. DCPP initiated AR A0443544 to reevaluate the need for testing or inspection of the flowpath. The team considered the fact that the UFSAR required flowpath was not being properly maintained (i.e., not in the maintenance rule) or tested to be contrary to the intent of GL 89-13 and a weakness in the licensee's program. This item is identified as URI 50-275/97-202-06, Availability of an Alternate Flowpath for the ASW System Suction.

i. System Modification

The team selected DCPP Modification DCPC-49207, “Auxiliary Saltwater System Piping Bypass Project" for review. This design change bypasses approximately 800 feet of Unit 1 and 200 feet of Unit 2 existing ASW piping which will be abandoned in place because of pitting/corrosion. This was essentially a piping/structural modification and the team's review was limited to verifying the impact of the bypass on the ASW system flow and how prevention of future pipe corrosion was addressed for the bypass. Mechanical calculation M-988 was prepared to address the effect on ASW flow due to the bypass. The team determined that the increase in head loss due to the additional length of piping was not significant, and the ASW system design flow would still be maintained. The team identified that no portion of the bypass piping was buried in saltwater which would significantly reduce pitting/corrosion in piping. A cathodic protection system to minimize pitting/corrosion has been or will be provided for all ASW system buried piping, and it will be maintained with a recurring task maintenance program. The above two design issues were adequately addressed by the modification. It should be noted here that the NRC is also currently reviewing this modification to determine its impact on other design and licensing issues.

E1.2.1.3 Conclusion

The team concluded, that with both ASW trains tied together, the ASW system design was adequate to remove the plant heat from the CCW system and transfer it to the UHS. The ASW system did not have the design ability to withstand a single active failure with the trains separated. The trains could only be separated during post-LOCA recirculation, if it became necessary based on guidance from the TSC, to withstand a single passive failure in the other train. This configuration of operation of the ASW system deviates from its original design and licensing bases and further review is required by the NRC. During post-LOCA recirculation, because of the reduced ability of the ASW system to remove the heat with only one CCW heat exchanger available, entry to the recirculation mode is restricted by EOP 1.3, which requires limiting operation for containment heat removal to only 3 CFCUs and 1 RHR heat exchanger. Even under low-low and tsunami tide levels, the ASW pumps have adequate NPSH to provide the minimum design flow through the bypass piping. The ability of the pump to provide flow is demonstrated through regular surveillance testing. The ASW pump intake screens are not seismically qualified and the alternate demusseling line path has not been demonstrated to be available. Recent changes to the ASW system design, because of the bypass modification and the CCW system design changes, require upgrading/superseding or archiving many of the ASW system calculations, DCM S-17B, the UFSAR, and other related design documents to maintain design configuration control.

E1.2.2 Electrical

E1.2.2.1 Scope of Review

The scope of review of the electrical inspection was the essential power supplies to the ASW, CS and CFCU systems. The following power supply areas were chosen for review: Emergency Diesel Generators, 4160 Volt AC buses, 480 Volt MCCs, 125 Volt DC System and Vital 120 Volt Instrumentation AC System. These areas were common to the three systems being assessed. The following attributes for the above areas of review were assessed by the team: equipment qualifications and sizing; regulation and standard compliance; channel separation; voltage drops;

controls, interlocks, alarms and indications; pump, fan and valve motor operations; protective device sizing, coordination and setpoints; field installations; cathodic protection; modifications; laboring and identification; and fire barrier penetrations.

The team reviewed UFSAR Chapter 8.3, "Onsite Power Systems," Technical Specification 3/4.8, "Electrical Power," Safety Limits Basis B 3/4.8, "Electrical Power Systems," various DCMs, calculations, procedures, drawings and other miscellaneous electrical documents.

E1.2.2.2 Findings

a. Emergency Diesel Generators

The team's assessment of the emergency diesel generator (EDG) standby electrical power system determined that adequate capacity to supply the predicted essential load profile sequences for Loss of Offsite Power (LOOP), occurring with other abnormal conditions, was provided. The computer simulated study for the EDG's responses to the application of the load sequences was not well documented and led to confusion regarding the diesel's performance. This assessment was based on the team's review of DCM S-21, schematic and single line diagrams, protective relay setpoints, the 015 series calculations including calculation 015-DC, "Diesel Generators, Vital Load Centers, 4 kV Switchgear Buses F, G and H - To Demonstrate the Emergency Diesel Generator's Worst Case Maximum Steady-State Loading is Within the Capabilities of the Diesel Generators," Revision 13. Some of the diesel protective relays only required during diesel testing were erroneously identified in Revision 01 of DCM T-18 as being required to perform a safety function. Revision 0 of the DCM had correctly identified these relays as being required during testing of diesels only. The team determined that a sentence from Revision 0 was inadvertently omitted from Revision 01 causing the error. AR A0442586 was issued by DCPP to revise DCM T-18 and evaluate the issue for root cause and generic implications.

Paragraph 4.3.1.j of DCM S-21 stated that, "Each diesel-generator set is designed so that at no time during the loading sequence will the frequency decrease to less than 95 percent of nominal frequency. [R.G.1.9]." Paragraph 4.3.1.n stated that "The diesel-generator sets are designed to ensure that nominal frequency is restored within 2 percent of nominal in less than 40 percent of each load sequence time interval. [R.G.1.9]." Regulatory Guide 1.9 Revision 1 revised the 40 percent criteria to 60 percent but the DCM did not reflect this allowance. UFSAR section 8.3.1.1.13.1 has similar descriptions of capability. When the team questioned the licensee as to their commitment for bus frequency and recovery time the licensee pointed out that EDG loading had been discussed with the NRC in PG&E Letter DCL-85-132, dated March 29, 1985. In that letter, the licensee described how testing demonstrated that their equipment met "the intent of" Safety Guide 9 or Reg Guide 1.9 Revision 0. The licensee also pointed out that it was not clear from docketed correspondence that the NRC responded to their 1985 letter about "intent of" since the original SAR indicated that Reg Guide 1.9 was met.

The team reviewed calculation 215-DC, Revision 1 dated 12/26/96, "EDG Loading Capability Study without KWS Relay." In this study, a computer simulation was used to analyze the machine's transient responses. The results for four of the six diesel generators showed the frequency dropping to 56.8 Hz. or slightly below the 57 Hertz minimum criteria during design basis loading. The frequency dip occurred during the initial load block when none of the ECCS motors were loaded, and the only load on the diesels were the 480 volt transformers. Also, during this

initial load block, one machine had a frequency recovery time of 2.54 seconds, which slightly exceeded the 2.4 second (60%) criteria of NRC Regulatory Guide 1.9. The Integrated Test of Engineered Safeguards and Diesel Generators (Surveillance Test Procedure STP M-15) conducted on the diesels to monitor their performance, however, do not show any dip in frequency below 57 Hz. or recovery time greater than 2.4 seconds. This difference between the computer study and actual tests was determined to be due to the slow governor response modeled in the analysis. The study also showed that for the non-design-bases case when three motors were loaded simultaneously the frequency dipped to 55.68 Hz.

The team's review determined that the computer simulation study results and EDG design requirement for transient loading were not well documented and led to confusion during the inspection. DCPP initiated AR A0444243 to evaluate current system capabilities, to resolve the discrepancies in their commitment to EDG response transient loading, and to revise calculation 215-DC as necessary. This item is identified as URI 50-275/97-202-07, EDG Transient Analysis Response Capability.

b. 4,160 Volt System

The team reviewed the 4160 Volt system and determined that the 4,160 Volt supply to the ASW pump motors was adequate. The ASW pump motor rating was increased from 400 horsepower to 465 horsepower to accommodate the ASW pump change to a larger size impeller.

For the 4,160 Volt system, the team reviewed DCM No. S-63, “4160V System," Revision 2, drawings, protective relay setpoints and coordination calculations. The team also conducted a walkdown of 4160V equipment rooms. The focus was on the under voltage protection schemes and the automatic bus transfers to the 230 kiloVolt off-site supply upon loss of power from the main generator or the 500 kiloVolt transmission system. The first level under voltage is set at approximately 69% of bus voltage, which is just below the level at which vital motors are designed to operate without breakdown. [Calculation 114-DC “Protection Relay Settings for Bus and Feeders (Class 1E 4.16kiloVolt Switchgear)," Revision 4A]. The second level of under voltage tripping is set at just above 90% of the vital motor terminal voltages. This assures that essential motors will start. [Calculation 357K-DC “4.16 kV Second Level Under voltage Relay & Timer Setpoint Calculation (DE&S Calculation No. 0017-00301.C002) ," Revision 0]. Upgraded timers are provided to prevent spurious transfers, shed load, start and load the diesel generators and start the sequenced vital loads.

c. 480 Volt System

The team assessed the adequacy of the 480 Volt system including essential supply and control of pumps, fans and motor operated valves to verify conformance to single failure criterion, equipment sizing, and availability of voltage at equipment terminals. The team determined that the design was adequate except for the following:

> Per DCM No. S-64, “480 Volt System,” Revision 2, and other design documents, each of the three vital 480 Volt busses is aligned to a particular vital 4,160 Volt bus. The DCM states that to meet the single failure criterion, the vital loads on any two of the three vital buses are designed to meet the safe shutdown requirements. To verify this, the team reviewed licensee provided marked-up operation valve identification drawings (OVIDs) for ECCS (injection phase and cold leg recirculation), CCW, ASW and the CFCUs indicating

alignments for four conditions: no bus failures, bus F failure, bus G failure, and bus H failure. The criterion was met as long as the ASW system cross-tie was open.

A review by the team of calculation 195A-DC, "Evaluate Adequacy of the Existing Thermal Overload Setting for 460 V Continuous Duty Motors," Rev. 4, determined that the thermal overload heaters (TOL) selected for the CFCU motor protection were slightly oversized. An exception note in this calculation stated that the lower size TOL were not selected as they did not satisfy acceptance criterion 1&2 of the design requirements. The team's evaluation of the lower size heaters indicated that this statement was not correct. The team reviewed calculation 205A-DC, "Evaluation of Reverse Rotation of CFCU on Electrical Protection System," Rev 0, and determined that the selection of the slightly oversized heaters was to provide adequate margin during starting to prevent any undesirable trip when the CFCU fan motors were started with the fans in reverse rotation. The exception note in calculation 195A-DC should provide the correct explanation for selection of the higher size heater than the existing note which was not correct. DCPP initiated AR A0443258 to correct the above exception note in the calculation.

The team also determined from review of calculation 195A-DC in conjunction with DCNs DC1-EE-47513, 45797 and 47195, that the current as built settings for TOL for ASW system motor operated valves 9001A and 9001B and flow control valves FCV-495 and 496 were included in the DCNs and not updated in calculation 195A-DC. AR A0444411 was initiated by DCPP to incorporate the DCN data in a revision to calculation 195A-DC. The team discussed with the licensee their controls for calculations. Procedure CF3.ID4, "Design Calculations," Revision 2, requires that calculations affected by a design change be identified and revised prior to closure of the design change package. The procedure does not however, require that calculations that are made obsolete by a change be automatically archived or made historical. The licensee's position is, that these superseded calculations served their purpose of forming the basis for the previous design and through other controls engineers are made aware of the current calculations. During the course of this inspection, the team had difficulty determining the most current calculations that supported the system design. The licensee's program depends heavily on people to remember the calculational history. This item is identified as example 1 of IFI 50-275/97-202-08, Control of Calculations.

d. Vital 125 Volt DC System

The team reviewed the essential 125VDC system including the batteries and chargers and verified that the system was adequately designed to perform its safety function. The team identified two issues in the DC system concerning the setpoint for the battery charger and the battery float and equalize voltage.

DCM No. S-67, "125V and 250V DC System," Revision 2, was reviewed to assess the adequacy of the essential 125 Volt DC system including the batteries and chargers. The recently replaced 2,320 ampere-hour batteries meet the UFSAR design commitment for a two hour minimum duty cycle to restore AC power to the battery chargers following a LOOP with margin. These capabilities are confirmed by calculations, 235A-DC, "Battery 11 - Sizing, Voltage Drop and Short Circuit Calculations," Revision 1; 236A-DC, "Unit 1 Battery Charger Sizing Calculation for Battery Charger 11, 12, 121, 131 & 132," Revision 1; and by Surveillance Test Procedures STP M-12C11, "Station Battery 11 Service Test," Revision 1A; and STP M-12A11, "Station Battery 11

Performance Test," Revision 1. The accident loads on the battery chargers are about one-half of the 400 amp rating. This provides the other one-half of the amps for the recharging of a discharged battery within twelve hours, as required by the UFSAR.

The vital battery chargers are sized by calculation 236A-DC, and the current revision of this calculation takes credit for a maximum charger capability of 110% of the full load rating (440 amps). Again as per UFSAR Sections 8.3.2.2.1.4, 8.3.2.2.1.2, 8.3.2.2.2.4 and DCM No. S-67 Section 4.3.3.1 for Battery Chargers, the charges are set at sufficient capacity to carry loads up to 110 percent of its 400 ampere rating and are set to current limit at 110% of rated output current. However, Maintenance Procedure MP E-67.3A, "Routine Preventive Maintenance of Station Batteries," Section 7.19.6 sets the "current limit to 430 (425-435) Amps by adjusting P5 on the Current Control Module." At this present setting of 107.5%, the battery charger has adequate capability to supply the DC loads for analyzed accident scenarios. The current available to recharge a totally discharged battery is slightly reduced and this will lengthen the time required for recharge but will still be less than the twelve hours required by the UFSAR. The 107.5% battery charger setting is not in agreement with calculational assumptions. DCPP initiated AR A0441745 to reconcile the difference between the design bases and actual setting for the battery chargers.

The present battery float voltage setting is 135 Volts plus control tolerances that could allow it to be 135.9 Volts. This is 5 Volts above the TS 4.8.3.1.a.2 minimum requirement of "greater than or equal to 130 Volts on float charge." The Vendor manual from C&D, the battery Vendor, specifies a nominal float Voltage per cell of 2.20 to 2.25 Volts, which is 132 to 135 Volts for the 60 cell vital batteries. The team identified that a higher float voltage can tend to "bake" normally energized DC coils which may shorten the usable life of equipment. However, setting the float at 135 Volts can be beneficial since fewer equalizations would be necessary. DCPP issued AR A0444410 to reevaluate the float Voltage setting.

DCPP selected a nominal equalize Voltage of 138 Volts. For equalizing charge, C&D recommends a range of 2.33 to 2.38 Volts per cell which is 139.8 to 142.8 Volts for 60 cells. The DCM S-67 defines the recommended DC System maximum operating limit of 139.8 Volts. Setting the equalize level at 138 Volts has no serious consequences except to reduce the effectiveness of the equalization. The team identified that DCPP's rationale for operating the battery outside of the battery manufacturer's float and equalization range recommendations was not clear. DCPP initiated AR A0444410 to review the setting for the battery float and equalize voltage.

Review of the licensee's evaluation and resolution of these three items is identified as IFI 50-275/97-202-09, Review of Battery Charger Settings.

e. Vital 120 Volt Instrumentation AC System

The team examined the adequacy of the vital 120 Volt Instrumentation AC system. The equipment in this system was determined to be sized and tested adequately. The team did however, question the possibility of operating the 120 Volt system at a voltage above the nuclear instrumentation qualification. The foam's analysis was based on review of DCM No. S-65, "120V AC System," Revision 2, calculation 093-DC, "Load Tabulation for Nuclear Instrument UPSs and Distribution Panels," Revision 7; and Operating Procedure OP J-10:II, "Instrument AC System -Alignment Verification." Specifically OP J-10:11 established an acceptance criteria of 116 to 124

Volts AC for the vital 120 Volt UPS. With the 2% instrument uncertainty the reading could be considered acceptable and be outside the values established in the calculation. There is a potential for out of specification voltage to be applied to the Nuclear Instrumentation with the present verification criteria. DCPP is reviewing this issue under AR A0444409.

f. Cathodic Protection Systems

Due to some recent failures and replacement of buried ASW piping between the Intake Structure and the Turbine Building, the team examined the plant's cathodic protection and grounding. The team reviewed DCM No. T-21, "Grounding," Revision 1; DCM S-68, "Lighting, Heat Tracing, and Cathodic Protection Systems," Revision 3; data from Maintenance Procedure MP E-72.2, "Monthly Cathodic Protection System Monitoring," Revision 3A; and various drawings. The Licensee is in the process of installing additional cathodic protection in the vicinity of the ASW piping and the diesel generator fuel tank. The installed cathodic protection at the Intake Structure appears adequate. Exposed buried grounds near the Unit 1 startup transformers were in good condition.

g. Electrical Protection Systems

The team assessed DCM No. T-18, "Electrical System Protection," Revision 1, and DCM No. T-23, "Miscellaneous Electrical Devices," Revision 2, for the adequacy of the protective devices, coordination and settings. The team examined the 195 series of calculations and especially 195C-DC, "Evaluate adequacy of the Existing Thermal Overload Settings for 460 V Motors for MOVs," Revision 2A. The setting methodology was found to be adequate and questions or concerns raised in the review of the 195 series were discussed and satisfactorily addressed. Other aspects examined were protection schemes, equipment sizing, circuit breaker sizing and settings, trip coordination and short circuit calculations as they relate to the ASW, CS and CFCU systems.

h. Channel Separation and Isolation

The installed channel separation between mutually redundant circuits was examined on a sample basis. Two redundant cable circuits were chosen for review from each of the three system being assessed: CFCU, ASW and CS. The following drawings were used:

- Setroute Reports (2 pages each) for Cables: F01P02 and H01P02 (Containment Fan Cooler Units 12 and 14), F08H02 and G06H02 (ASW Pumps 11 and 12), G21P02 and H11P02 (CS MOVs 9001A and 9001B)
- Schematic Diagrams: 437600 (CFCU), 437594 (ASW), 437604 (CS)
- Diagram of Connections: 437736, 437738, 437795, 437802, 437807, 437808, 448923, 448922, 448924
- Cable Tray and Conduit Layout Drawings: 57563, 57568, 57597, 57600, 57601, 57606, 57612, 57619, 501452.

The team concluded that the divisional or channel separation of the samples was in compliance with the requirements of UFSAR Section 8.3.1.4 and DCM No. T-19, "Electrical Separation and Isolation."

i. Code and Standard Compliances

There were several observations about the documents provided for the inspection that were discussed with the licensee. First, the revision dates of industry standards used for reference, for developmental purposes and for licensing commitments are inconsistently listed in the UFSAR, Technical Specifications, DCMs, calculations and procedures. IEEE standard 450, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations," was cited and discussed as an example. The problem extends to many other standards, as well. DCPP generated AR A0444408 to address these deficiencies. Second, the status of calculations was confusing. Specifically, there are situations where limited scope calculations (i.e., smaller calculations) were performed. Data in these smaller calculations may supersede information in a larger calculation. There is no periodic updating of the major calculations to incorporate the collected small revisions. This same condition was also true for other functional reviews discussed elsewhere in this report. Resolution of this item is identified as the second example of IFI 50-275/97-202-08, Control of Calculations.

E1.2.2.3 Conclusion

The team concluded that the aspects inspected of the essential power supply for the ASW, CS and CFCU systems support the conclusion that the supply is adequate. The calculations were generally conservative in approach, used appropriate methodology, produced reasonable results, and were consistent with the licensing documents. The design criteria cover the performance requirements, design requirements, developmental and code references, component descriptions, technical specifications, and limits. The essential 4,160 Volt and 480 Volt systems are adequate to power the pumps, fans and valves in the systems being assessed. When voltage is lost, the source is automatically transferred to a different available offsite supply or to the diesel generators within the prescribed time sequences. A solution for the diesel generator transient response is being pursued. The vital 125 Volt DC and vital 120 Volt Instrumentation AC systems are properly sized and function as required. Concerns about operating setpoints are being evaluated.

E1.2.3 Instrumentation and Control

E1.2.3.1 Scope of Review

The scope of the instrumentation and control design assessment consisted of a review of the ASW system design and associated documents. The review also included an assessment of interfacing portions of the CCW system. Documents that were reviewed included Chapters 6 and 7 of the UFSAR, technical specifications, design criteria memorandum, piping and instrument schematics, electrical schematics, logic diagrams, 11 calculations, the PIMS database, 2 surveillance procedures, 1 operating procedure and 1 modification package. System walkdowns and interviews with plant personnel were also conducted to verify as-built design.

E1.2.3.2 Findings

The system design documents reviewed by the team were consistent with the design bases, except for the items discussed in the following sections.

a. ESFAS initiation of ASW/CCW

The team reviewed the setpoint methodology and instrument uncertainty for the engineered safety feature actuation system (ESFAS) actuation of the ASW and CCW systems. The ASW and CCW pumps are automatically initiated on receipt of an Sl actuation signal resulting from a high containment pressure signal from the ESFAS. The actuation signal is derived from a 2 out of 3 logic from containment pressure transmitter channels PT-934, PT-935 and PT-936. The team verified that the TS Table 3.3-4 trip setpoint of 3 psig on increasing pressure was within the value provided in Westinghouse Calculation WCAP-11082, "Westinghouse Setpoint Methodology for Protection Systems Diablo Canyon Stations Eagle 21 Version," Revision 2. The team also verified that plant procedures correctly calibrated the instruments.

The team noted that calculation, J-98, "Containment Pressure ESFAS Setpoint," Revision 0, established a channel uncertainty value of 2.37%, which exceeds the uncertainty value of 2.1 % provided in the WCAP. This was due to different transmitter manufacturers used in the calculations. WCAP 11082 supports Barton 332 pressure transmitters which have been replaced, whereas J-98 supports the existing Rosemount 1154DP transmitters. The licensee indicated that Calc J-98 is considered temporary until such time when WCAP 11082 is updated to incorporate the Rosemounts. As a result of Calc J-98, the uncertainty of the Rosemounts exceeded those of the Bartons but the calc justified that there is sufficient margin to warrant the use of existing setpoints and TS values. WCAP 11082 is scheduled to be updated after approval of licensing amendment request LAR 96-10 for a 21-month refueling cycle extension. The licensee is committed to ensure correct instrument data is reflected in this update.

Based on the team's review, adequate setpoint margin has been provided in the actuation of the ASW system from the containment high pressure signal.

b. ASW/CCW RG 1.97 Instrumentation

There is no specific RG 1.97 I&C requirement for the ASW system. However, the RG requirements apply to the CCW interface system. UFSAR Section 7.5 and Table 7.5-6, DCM T-24, and letter DCL 93-284 provide the design bases for the CCW RG 1.97 instrumentation. Required instrumentation consists of main control room indication for CCW flow to the vital supply headers and CCW heat exchanger outlet temperature.

One CCW flow indicator is provided in the main control room for each vital header (loops FT-65 and FT-68). Outlet temperature indicators (loops TE-6 and TE-7) for CCW Heat Exchangers 1-1 and 1-2 are also provided in the control room. RG 1.97 requires these instrument loops to be designed as Type D, Cat. 2, variables requiring a standby power source. The team reviewed scaling calculations SC-M-14-T6, "Instrument Scaling Calculation CCW Heat Exchanger Outlet Temperature Channels TE-6 & TE-7," Revision 1, and SC-M-14-F68, "Instrument Scaling Calculation CCW Supply Headers A and B Flow Channels FT-68 and FT-65," Revision 0, uncertainty calculation PAM-0-0-001, "Misc. Post-Accident Monitoring Indication Uncertainty," Revision 3; design documents; and as-built condition with respect to indication range, calibration span, accuracy and power supply for these instrumentation. The team verified that both the CCW flow and temperature instrumentation met the licensee's commitment to RG 1.97.

c. ASW/CCW Instrument Loop Accuracy, Scaling and Setpoint Calculations

The team reviewed the setpoint methodology and uncertainty calculations for the following instrument loops to verify that adequate tolerance for instrument error has been incorporated in the design:

1. CCW Heat Exchanger high and low differential pressure
   a. NSP-1-17-15, “CCW Heat Exchanger High DP Alarm,” Revision 2
   b. NSP-1-17-15A,"CCW Heat Exchanger Low DP Alarm,” Revision 2
2. CCW Heat Exchanger discharge temperature
   a. NSP-1-14-181A, CCW Heat Exchanger High Alarm Setpoint Uncertainty,” Revision 0
   b. NSP-1-14-181B, CCW Heat Exchanger Low Alarm Setpoint Uncertainty,” Revision 0
3. ASW Discharge Flow and Temperature Indication
   a. C-M-26-1, "ASW Flow Annubar Uncertainty,” Revision 0
   b. J-103, "ASW byp. piping PME temp. and Flow channel Indic. Uncertainty,” Revision 1
4. ASW Pump vault high level alarm
   a. SC-L-17-22A, "Instrument Scaling Calculation Auxiliary Saltwater Pump Room High Water Level Switches LS-355 and LS-356,” Revision 0
5. Ocean Temperature
   a. SC-M-17-T10, "Instrument Scaling Calculation Circulating Water Pump 1-1 Discharge Temperature Channel TE-10,” Revision 0

The team's review determined that the above calculations adequately demonstrated instrument capability to perform its intended function. However, an inconsistency was noted between calculations NSP-1-17-15 and NSP-1-17-15A, concerning the use of bias error due to static pressure effects in the loop uncertainty calculation. Since both CCW heat exchanger high and low DP alarm loops PS-45/46A and PS-45/46B derive input signals from a common DP transmitter, the static pressure effect applies to both loops. This error term was assumed as a zero value in NSP-1-17-15. Based on the licensee's evaluation, the effect would be on the conservative side, therefore, there is no safety impact. The licensee acknowledged this error and noted that calculation NSP-1-17-15 would be revised.

d. Ocean Temperature Monitoring

Procedure STP I-1A, "Modes 2 and 3 Shift Checklist,” relies on the ocean temperature indication for operator action to manually initiate operation of the redundant CCW heat exchanger. Ocean temperature is indicated by Tl-311 and Tl-328 on the control room vertical board. These indicators are not RG 1.97 qualified, classified as Class II, not seismically qualified and are not connected to standby power. Tl-311 measures temperature downstream of the circulating water pump, so on a loss of power to the pump it would not provide accurate indication of ocean temperature. Tl-328 measures temperature in the ocean bay upstream of the ASW intake. Although not mentioned in the procedure, a multi-point temperature recorder (loop TE-68) is available near the hot shutdown panel to indicate ocean temperature through a separate sensor located upstream of the bar racks. This recorder is powered from an emergency bus and will provide an alternate method of indication. This design assures that ocean temperature indication is available through diverse

channels, including accessibility of similar instrumentation in Unit 2. A note on page 9 of procedure STP I-1A instructs the operator to obtain corrected Pacific Ocean temperature from Unit 2 instrumentation if no circulating water pumps are operating. Although not required to be safety related, reliable indication of ocean temperature should be available to the operator if needed.

e. TS and DCM Discrepancies

TS 3/4.3.1 and 3/4.3.2, page B3/4.3-1, 4th par., ESFAS, lists those actions that are initiated by the ESFAS to mitigate the consequences of a steam line break or loss of coolant accident. However, initiation of the ASW as described in UFSAR Sec. 7.1.2.1.2.2 is not referenced. The actual design complies with the UFSAR. This issue does not constitute a safety concern since the licensee's design, drawings, and testing included the initiation of ASW by the ESFAS signal. The licensee concurred with this discrepancy and issued AR A0442762 to initiate corrective action to clarify the TS basis.

TS 3/4.5.5, page 3/4 5-11, RWST Surveillance Requirements, describes verifying the RWST temperature to establish operability during low outside ambient temperature conditions. However, TS bases 3/4.5.5, page B3/4 5-7, only mentions RWST volume and boron concentration as a requirement for operability. As indicated in the UFSAR and surveillance procedure STP R-20, temperature is verified along with boron concentration when performing surveillance of the RWST. This issue does not constitute a safety concern and the licensee will track this issue for correction as part of a planned effort to standardize the DCPP TS. This item is identified as the second example of
URI 50-275/97-202-05, Discrepancy in Design Documentation.

E1.2.3.3 Conclusions

The instrumentation and control design for the ASW/CCW system was considered adequate. The above findings do not constitute any operability concerns. Weaknesses were observed in maintaining consistency between the UFSAR, Technical Specification, Design Criteria Manual and associated design documents. The licensee's resolution of issues raised by the team are being addressed through their corrective action system.

E1.2.4 System Interface

E1.2.4.1 CCW Heat Exchanger

To verify the heat load required to be removed by the ASW system and be transferred to the UHS, the team reviewed portions of DCM S-14, "Component Cooling Water System," Revision 04; CCW calculations M-305, 910, 938; and Westinghouse analysis WCAP-14282 and PGE 96-503 associated with the CCW system. The issues related to determining the heat load for the CCW system and the team's evaluation is addressed in Section E1.2.2.2.2.

E1.2.5 System Walkdown

E1.2.5.1 Scope

The team inspected the installed mechanical, electrical, and instrumentation and control equipment for the ASW system to evaluate their consistency with drawings, design specifications, and regulatory requirements. During the walkdown the team interviewed plant system engineers, and operations and maintenance personnel. The team walkdown covered the Intake Structure, CCW heat exchanger room in the Turbine building, control room, auxiliary shutdown panel, cable spreading room, switchgear rooms, battery rooms and electrical distribution panels.

E1.2.5.2 Findings

a. Intake Structure and CCW Heat Exchanger Room

During walkdowns of the Intake Structure and Turbine Building and questioning of licensee personnel, the team verified adequate equipment installation design related to train separation, seismic interaction, internally generated and externally generated missiles, and protection of Intake Structure and snorkels against tornado and winds. Additionally, the team verified that, (1) the location of snorkels and ducts maintained adequate cooling for ASW pump motors during high tide and floods, (2) clogging and silting of the pump bay had been evaluated and considered in the design, and (3) flooding had been adequately considered in ASW pump vault design. The team verified that flooding had also been addressed in the CCW heat exchanger room design and effects of high energy line breaks in the vicinity were considered.

b. CCW Pumps

The CCW pump area walkdown indicated some unidentified debris accumulated in the 1-3 pump inboard seal housing enclosure. The material did not appear to interfere with current pump operation. The licensee initiated actions for Maintenance to clean up the materials in the seal housing during the next shutdown of the pump.

c. ASW Pump Discharge Pressure Indication

During the walkdown of the ASW pump vault, the team noted the Unit 1 ASW pump discharge pressure at 30 psig, as indicated by Pl-452. The corresponding reading on the Unit 2 pump was at 50 psig, as indicated by Pl-452 (Unit 2). The team questioned the large deviation in the readings, considering that Units 1 and 2 are similar in design. The system engineer concluded that Unit 1 was reading lower than normal (48 psig), which could be associated with the instrumentation since all other pump parameters were within specification. As a resolution, AR A0441411 was issued to initiate investigation and subsequent corrective action.

d. Instrument Tubing Slope.

During a walkdown of the ASW pump area, the team noted that instrument tubing for ASW pump discharge pressure instruments Pl-452/454 were not sloped per DCM T-38, "Criteria for Design of Instrument Tubing and Supports," Revision 1. In response, the Iicensee stated that this condition had been previously identified and evaluated with corresponding justification included under

Engineering Report DVR 5W, dated 3/17/91 and Quality Evaluation QE Q0009595, dated 9/8/92. Based on the team's review of the reports, this issue has been properly addressed.

e. ASW Pump Header Pressure Switches Below Flood Level

The team made the following observations regarding the ASW pump header pressure switches PS-185A and PS-186A:

1. Both instruments were mounted approximately 5' above the corresponding pump vault floor. This elevation was below flood level and the pressure switches could be submerged, resulting in a fault in the pump control circuit that could cause the redundant pump not to dart. These instruments are non safety related but they are connected to the safety related class 1E pump control circuit such that flooding of a pump vault concurrent with a ground fault in the battery system could render the redundant pump inoperable. Acceptability of this condition was not addressed in DCM S-17B, "Design Criteria Memorandum, Auxiliary Saltwater System," Revision 4.

2. Train A pressure switch PS-185A is located in ASW pump room B, and likewise for train B pressure switch PS-186A in pump room A.

The licensee acknowledged these observations and initiated the following corrective actions:

1. Issued AR A0441809 to document the condition and evaluate operability of the ASW system. A Prompt Operability Assessment (POA), included in the AR, provided the following justification as to why the condition did not affect system operability:

   - A detailed walkdown was performed and verified that the pressure switches are seismically mounted (Ref. Calc. IS-45, Revision 6). Failure mode during a seismic event will not short the contacts to ground but will cause starting of the redundant pump, which is conservative. An open pressure switch will not prevent the ASW from performing its safety function since a separate Sl start path is provided.

   - Existing control room procedures are in place to identify and mitigate potential DC bus grounds in a timely manner such that any significant DC ground is not considered concurrent with a moderate energy line break in a pump vault. Due to the heat storage capacity and mass of water in the CCW, temperature would increase slowly such as to allow enough time for operator action to restore ASW flow.

   - Existing manual start switches with separate fuses at the switchgear can be used to restore ASW flow.

2. Issued AR A0442005, initiating a design change to install isolation fuses in the pressure switch circuits to address the1E to non-1E auto-start interlock with the ASW pumps. This method is considered acceptable at DCPP and will not require revising DCM S-17B or upgrading the instruments to safety related classification. Implementation of the design change, scheduled during the next refueling outage for both Units 1 and 2, will close both ARs A0441809 and A0442005.

Based on the licensee's operability review and tracking of correction actions, the team found the licensee's actions acceptable.

E1.2.6 Updated Safety Analysis Report

The licensee had initiated a Licensing Basis and Design Bases Program (LBADB) in early 1997 to review and update the UFSAR. Action Request (AR) forms were prepared for the identified questions or concerns in the UFSAR related to the ASW system. Some of the AR forms were provided to the team for information. The team identified the following additional discrepancies:

- Section 9.2.2.1 states "Based on design basis accident heat load, one of the following four conditions must be satisfied as a minimum to maintain the ASW system design basis." Instead of "ASW" the statement should have read "CCW." AR A0441163 has been written to track the preparation of an UFSAR update change request.

- Various updates to the UFSAR will be necessary with revision of WCAP-14282. These are tracked by DCPP under AR A0439116

E1.3 Containment Spray (CS) System Design Review

E1.3.1 Mechanical

E1.3.1.1 Scope of Review

In evaluating the mechanical design of the CS system, the Inspection Team evaluated the capability of the system to provide containment spray during the injection phase of post-accident ECCS operation and the capability of the RHR system to provide spray during the recirculation phase of ECCS operation. The team reviewed design criteria memorandum S-12, Revisions 3 and 4 for the CS system, UFSAR sections 6.2 and 15.4, drawings, calculations, and normal and emergency operating and surveillance testing procedures. The team also performed system walkdowns and discussed the system design and installation with licensee engineering and operating personnel.

E1.3.1.2 Findings

a. Containment Spray during Post-LOCA Recirculation with One RHR Pump

The team reviewed the RHR system capability to support containment spray during post-LOCA with only one RHR pump (single failure) in operation. The team determined, based on a newly generated licensee calculation, that the RHR system may have the capability to provide containment spray during post-LOCA recirculation if core cooling is throttled. Extensive discussion on this issue follows.

The current UFSAR Section 3.1.8.16 specifies that the Containment Heat Removal System, designed to comply with the July 1967, GDC 52, consists of the Containment Spray (CS) and Containment Fan Cooler (CFC) Systems. UFSAR section 6.2.2.2.2.1 specifies that during the recirculation phase of the accident "recirculation spray suction is provided by the RHR pumps, which draw suction from the containment sump." Technical Specification 3.6.2.1 specifies that the

CS system shall be operable with each spray system capable of taking suction from the RWST and of transferring the spray function to the Residual Heat Removal (RHR) system taking suction from the containment sump.

By design, the RHR system provides the recirculation phase of containment spray by taking suction from the containment sump and discharging into the CS system piping and spray headers downstream of the CS pumps. The RHR system also provides core cooling by injecting flow into the RCS (LHSI) and providing the suction source for the HHSI and Sl pumps (“piggy-back").

In December 1991, the licensee discovered (LER 1-91-018) that the heat loads placed on the CCW system by two trains of RHR in the event of an accident with a loss of a single train of ASW would be unacceptable. The CCW system heat loads could be brought to within design limits by operating with only one train of RHR. Since the containment spray function is assumed by the RHR system during recirculation, PG&E believed that one RHR pump could <u>not</u> provide both adequate core cooling flow and containment spray flow simultaneously. No engineering calculation was performed to substantiate this belief, but it was felt to be an obvious conclusion based on pump curves and flow path resistances. Additionally, the licensee did not have a calculational basis for the original assumed ability of the RHR system to provide the containment spray function during the recirculation phase of the accident after a single failure occurred. Based on the new data (LER 1-91-018), PG&E initiated changes to the UFSAR to re-classify the containment spray function during recirculation as non-safety related, revised EOP E-1.3 to prohibit spray during recirculation with only one RHR pump in operation, and eliminate the UFSAR requirement to operate spray for a minimum of 2 hours. Westinghouse was requested to reevaluated the containment analysis to verify that two of the five containment fan coolers could remove the containment heat without the need to spray the containment using the RHR pump aligned to the containment sump. The team's review of the Westinghouse containment reanalysis is discussed in Section E1.2.1.2.c of this report.

Even though the LER only described single failure effects on the RHR system by a loss of ASW and CCW system capacity, this situation could also occur if there was a single active failure of an RHR pump during the injection phase or the loss of a single electrical bus as described in Section E1.2.1.2.d of this report. Additionally, since the licensee change essentially eliminated the containment spray function during the recirculation phase, the inspection team questioned the ability of the CS system to meet the TS requirements.

During the inspection, the licensee performed calculation STA-075 entitled; "Minimum ECCS Flow and Minimum Recirculation Spray Header Flow," dated August 29, 1997, to demonstrate that containment spray and core cooling could both be performed by a single RHR pump during recirculation. This calculation determined that by reducing RHR (LHSI) flow to the core the RHR pump could provide flow to the CS spray header. The decision to reduce ECCS capability in order to provide CS was at the discretion of the technical support center (TSC). Minimum available core cooling flow was calculated to be 1200 gpm with a corresponding available spray flow of 1000 gpm. However, the licensee's analysis did not determine the minimum required spray flow needed during the recirculation phase of operation since the containment analysis no longer depended on spray flow. The minimum required core cooling flow at the beginning of recirculation was determined to be 765 gpm based on a Westinghouse analysis, NSAL 95-001, "Minimum Cold Leg Recirculation Flow - ECCS Analysis" dated January 20, 1995. This Westinghouse analysis specified that a flow to the core equal to 1.2 times the core boil-off caused by decay heat was required.

b. Revision 9 to EOP E-1.3

The team reviewed the safety analysis performed to issue Revision 9 to EOP E-1.3; "Transfer to Cold Leg Injection." The team determined that this safety analysis failed to recognize that by prohibiting containment spray during recirculation if only one RHR pump was available they were also dealing with a newly discovered consequence of the single failure of the RHR pump. The team considered this to be a potential unanalyzed consequence of the malfunction of equipment important to safety.

In December 1991, PG&E determined that they should prohibit the containment spray function during recirculation if only one RHR pump is in operation. To do this, they prepared and issued Revision 9 to EOP E-1.3. As part of the revision process, the Operations Department completed a Safety Evaluation Screen Checklist
(NPAP C-19/NPG-4.3) for Revision 9 on December 13, 1991. All screening questions were marked ”no" and therefore no 50.59 safety evaluation was performed. Revision 9 of E-1.3 was then issued on December 13, 1991. Westinghouse, at the request of PG&E, subsequently completed a Nuclear Safety Evaluation Check List (SECL-91-458,
Revision 1) on January 10,1992. This Westinghouse evaluation concluded that the revision to E-1.3 did not result in an unreviewed safety question but one of the evaluation questions was marked "yes." Specifically, the question: "A change to procedures as described in the UFSAR?" was marked "yes." This led Westinghouse to perform a complete safety evaluation and recommend a change to UFSAR Table 6.3-5.

In the same time period, PG8E performed Operability Evaluation (OE) 91-15 (entitled; "CCW System Temperature During Post LOCA Reactor Coolant System Cold Leg Recirculation") which was issued on December 23, 1991 (Revision 0). This OE was required by station administrative guidelines to "sponsor" Revision 9 to E-1.3 and included a safety evaluation. This safety evaluation and the one performed by Westinghouse considered the following technical issues involved with the decision not to use containment spray during recirculation with only one RHR pump in operation and concluded that there were no safety concerns:

- There are no increases in the offsite or control room post-LOCA doses since the iodine is completely removed from the containment atmosphere by the CS system during its injection phase. In addition, the containment pressure is still reduced to one half its peak value within 24 hours so there is no increase in containment leak rate and resultant doses.

- The peak containment pressure is reached during the injection phase and long term containment pressure is controlled by the fan coolers and never required the use of containment spray. The fan coolers are capable of bringing the containment pressure to one half its peak value within 24 hours as required by the design basis without the use of containment spray.

- The lack of containment spray during recirculation alters the long term containment temperature/pressure profile. The altered profile has no impact on the environmental qualifications of the equipment inside containment.

Other technical issues not mentioned in the safety evaluations but discussed with the Inspection Team are as follows:

- Containment sump pH is not affected since all the NaOH in the Spray Additive Tank is pumped into the containment by the CS pumps during the containment spray injection phase.
- Long term post-LOCA hydrogen mixing in the containment has always been done by the fan coolers. The containment spray was never necessary for hydrogen mixing during recirculation.

These technical arguments are valid and appear to establish that the lack of containment spray during recirculation is acceptable and has no effect on the ability of the station to mitigate the consequences of a design basis accident.

The problems noted by the Inspection Team in the above safety evaluations involved the following: The Operations Department did no safety evaluation for Revision 9 to EOP E-1.3 before it was issued because their screening was in error. Westinghouse did a safety evaluation for the revision after it was issued and concluded that there was no unreviewed safety question but recommended an UFSAR change. In spite of this Westinghouse recommendation, PG&E did not change UFSAR Table 6.3-5. The Westinghouse safety evaluation and the one associated with OE 91-15 performed by PG&E both failed to recognize that TS 3.6.2.1 required that the RHR system provide the long term containment spray function during the recirculation phase of the accident. Additionally, the newly discovered consequence of the single failure of an RHR pump could also be considered to be an unanalyzed consequence of the malfunction of equipment important to safety. The Inspection Team considered this issue to be a potential unreviewed safety question that should have been brought to the attention of the NRC for review when the LER condition was discovered. This item is identified as URI 50-275/97-202-10, Potential USQ and TS Adherence Associated with Containment Spray During Containment Recirculation.

c. Recent Safety Evaluation on Containment Spray during Recirculation

Because of the concerns expressed by the Inspection Team with regard to the change in the original design basis as to containment spray during post-LOCA recirculation, PG&E prepared a new consolidated safety evaluation. The new safety evaluation was titled;
"10 CFR 50.59 Safety Evaluation for Reclassification of Containment Spray During the Recirculation Mode of Safety Injection As a non-safety-Related Function." The purpose of the document is to.".....consolidate, validate, and update....." the contents of the three safety evaluations done in 1991/92 as part of the process to issue Revision 9 to EOP E-1.3 (prohibit containment spray with only one RHR pump in operation) and to remove the
"2 hour" statement from the UFSAR. The new safety evaluation attempts to address two points; (1) the potential unavailability of containment spray during recirculation, and (2) the use of containment spray during recirculation under TSC direction with only one train of RHR in operation. This safety evaluation therefore does not replace any of the safety evaluations done in 1991/92 but is a new evaluation using PG&E's latest information such as Calculation STA-075. This calculation was done in response to issues raised by the Inspection Team and shows that, in fact, the RHR system can provide limited spray during recirculation with only one pump in operation with restricted flow to the core.

The Team determined that the licensee's response to Question 4 in this new safety evaluation involving the probability of occurrence or consequences of a malfunction of equipment important to safety previously evaluated in the SAR was marked “No.” The limitations on the use of containment spray during recirculation with only one RHR pump in operation were never

addressed in any revision of the UFSAR and therefore are a new ramification of the previously evaluated consequences of the single failure of an RHR pump. Additionally, as specified in 10 CFR part 50.59, a change to the facility or procedures specified in the UFSAR can not be made without prior Commission approval if it involves a change in the TS or is a USQ. The NRC is currently evaluating whether the licensee's change involved a USQ and whether a change to the TS should have been requested prior to the change. This item is included as part of URI 50-275/97-202-10, Potential USQ and TS Adherence Associated with Containment Spray During Containment Recirculation.

e. CS Pump Testing and Acceptance Criteria

The team reviewed DCM No. S-12, TS 3/4.6.2.1, Calculation N-085 (entitled "Containment Spray Profile" Revision 0 dated 6/28/93), and Surveillance Test Procedures
STP P-CSP-11, 12, 21 and 22. The team verified the adequacy of the regular surveillance test done for the CS pumps and its acceptance criteria to demonstrate pump performance. The team determined that the STP satisfies TS 3/4.6.2.1 requirements and provides assurance of satisfactory pump performance as required by ASME Section Xl.

E1.3.1.3 Conclusions

The Inspection Team concluded that the CS system was designed and tested to provide the design basis flows during the injection phase of post-accident recovery. The team also concluded that the RHR system, even with only one pump in operation, could provide the necessary core cooling flow and some quantity of containment spray during the recirculation phase. The licensee considers the ability to provide containment spray during recirculation to be technically unnecessary.

The Team considers the licensing methodology employed by the licensee to re-classify the containment spray function during recirculation as non-safety related and to prohibit spray during recirculation with only one RHR pump in operation to be a potential USQ requiring further NRC review. Additionally, essentially abandoning a TS required function should have occurred only after changing the plant TSs.

E1.3.2 Electrical

The electrical discussion in Section E1.2.2 of this report covers the electrical design review of the CS system.

E1.3.3 Instrumentation and Control

E1.3.3.1 Scope of Review

The scope of the instrumentation and control design assessment consisted of a review of the CS system design and associated documents. Interfacing portions of the RHR system were also reviewed. Documents that were reviewed included Chapters 6 and 7 of the UFSAR, technical specifications, design criteria memorandum, piping and instrument schematics, electrical schematics, logic diagrams, 15 calculations, PIMS database, 2 surveillance procedures and 1 operating procedure. System walkdowns and interviews with plant personnel were also conducted to verify as-built design.

E1.3.3.2 Findings

The system design documents reviewed by the team adequately supported the design bases, except for the items discussed in the following paragraphs:

a. ESFAS Initiation of CS System

The team reviewed the setpoint methodology and instrument uncertainty calculations for the ESFAS actuation of the CS system. A high-high containment pressure (P)signal from the ESFAS concurrent with a Safety Injection (S) signal automatically initiates operation of the CS pumps. The team verified that plant procedures properly calibrated the instruments to the TS trip setpoint values.

The team did however, note a discrepancy in DCM S-12, Section 4.3.1.g, which provided a description of the initiating signal for the CS system. The DCM section described only the "P" signal for automatic actuation of the CS system. According to UFSAR Chapter 7 and Logic Diagram 4014233, a coincident "P" and "S" signal is required to initiate automatic actuation, which is consistent with the design documents. This discrepancy has no safety impact. The issue involves an inconsistency between the design criteria document and the UFSAR. The licensee concurred and noted that AR A0438244 resolution will correct the DCM. This item is identified as the third example of URI 50-275/97-202-05, Discrepancy in Design Documentation.

b. CS System RG 1.97 Instrumentation

UFSAR Section 7.5, UFSAR Table 7.56, DCM T-24, "Diablo Canyon Power Plant Instrumentation and Controls," Revision 2, and letter DCL 93-284 provide the design bases for the CS system RG 1.97 instrumentation. Required instrumentation consists of CS pump flow and RWST level indication in the main control room.

One containment spray flow indicator is provided on Main Control Room Panel PAM1 for each CS pump (FI-931and Fl-932). RG 1.97 requires CS pump flow instrumentation to be designed as a Type D, Cat. 2, variable requiring a class 1E power source. Three redundant RWST level indicators (Ll-920, 921 and 922) are provided in the main control room. RG 1.97 lists RWST level instrumentation as Type D, Cat. 2. However, DCPP upgraded them to a Type A, Cat. 1 variable requiring redundancy and full Class 1 E qualification. The team reviewed scaling calculations
SC-I-9-L920, "Instrument Scaling Calculation Refueling Water Storage Tank 1-1 Level Channel LT-920, " Revision 1; SC-I-9-L921, "Instrument Scaling Calculation Refueling Water Storage Tank 1-1 Level Channel LT-9211" Revision 1; SC-I-9-L922, "Instrument Scaling Calculation Refueling Water Storage Tank 1-1 Level Channel LT-922," Revision 1; "Scaling Calculation RWST 1-1 Level Channel LT-920/921/922," Revision 1; uncertainty calculation PAM-0-09-920, "Normal Operation and Post Seismic RWST Level Indication Uncertainty," Revision 4; EQ Reports IH-24 and IH-32; and cosign documents and as-built condition with respect to indication range, calibration span, accuracy, qualification and power supply for this instrumentation. During a walkdown of the control room, the team identified a discrepancy between RG 1.97 and DCM T-24 in regard to "PAMS" labeling of instruments on Panel PAM1. Labeling was consistent with RG commitments, however, AR A0443473 was issued to correct the DCM.

The results of the review verified that both the CS pump flow and RWST level instrumentation met RG 1.97 commitments.

c. RWST Level Instrumentation

TS Section 3/5.5 requires a minimum contained volume of 400,000 gallons with a 2300 to 2500 PPM boron concentration in the RWST for the post-LOCA injection function. Three redundant level instrument loops (LT-920, LT-921 and LT- 122) provide input for indication, trip the RHR pumps on Low RWST level and a low-low level alarm to signal depletion of the RWST. Boron concentration is verified through manual sampling and chemical analysis (Ref. Procedure STP
R-20, "Boric Acid Inventory," Revision 17). Setpoint bases for the RWST is provided under Westinghouse PLS document, "Precautions, Limitations and Set Points for Nuclear Steam Supply Systems, " Revision 9, Document DC 663229-47-10. The PLS provided setpoints and tolerances in gallons of level for the following; Hl level alarm, LOW level alarm and RHR pump trip with an alarm, and LO-LO level alarm.

RWST volume scaling calculation TV-9-2, "Scaling calculation for RWST," Revision 3, and transmitter scaling calculations SC-I-9-920 through SC-I-9-922 translated the above Westinghouse PLS values to % level. In addition, the team also reviewed uncertainty calculation PAM-0-09-920," Normal Operation and Post Seismic RWST Level Indication Uncertainty," Revision 4, and J-54," Nominal Setpoint Calculation for Selected PLS Setpoints," Revision 10, the PIMS database, and the instrument calibration data sheets. The team determined that the RWST level transmitters were properly spanned, compensated, and calibrated to account for boron concentration and differences in elevations. Additionally, the team verified that adequate margin has been provided in the determination of setpoints and indication accuracy of the RWST level instruments.

d. Spray Additive Tank (SAT) System Instrumentation

The SAT system instrumentation was assessed to verify its capability to measure the amount of sodium hydroxide solution that is added to the containment spray. Level instrumentation loop
LT-931 measures SAT volume by monitoring hydrostatic pressure, which is not linear with the tank volume (consists of a horizontal cylinder with spherical ends). A correlation between indicated level and contained volume was established by TV-12-1, "Scaling Calculation for Spray Additive Tank 0-1," Rev.0. TS Section 3/4.6.2 requires a SAT contained volume of between 2025 and 4000 gallons of solution containing between 30 and 32% NaOH by weight, to ensure the proper pH value for recirculated solution in the containment. A low SAT level equal to or less than
60% +./-1%, as established by the Westinghouse PLS document, is alarmed in the main control room. Per calculation J-54, calibration of this instrument loop results in an alarm setpoint that corresponds to 2570-2707 gallons contained volume in the SAT. The DCPP design does not provide a LO-LO SAT level alarm to alert the control room when the tank contents have been exhausted.

UFSAR Section 6.2.3.5.3, Spray Additive Tank Instrumentation, states that two alarms are provided to announce that the SAT solution has been exhausted. Based on a verification of control room annunciator layout drawing 500808 and the as-installed condition, only one alarm exists which is on window group PK01. Also, contrary to the UFSAR description, this alarm is to announce that the TS level of 60% in the SAT has been reached, instead of being exhausted. This discrepancy also affects Instrument Schematic 102033 Sh. 18 and DCM S-12, par. 4.3.9.1.

The licensee concurred with this discrepancy and issued AR A0442941 to revise the UFSAR, Instrument Schematic and DCM S-12. The licensee does not consider that a tank LO-LO alarm is necessary for CS pump protection since emptying of the SAT and injection of gasses into the system will not have an adverse effect. Therefore, the existing design which consists of one alarm, provides sufficient information to evaluate the condition of the SAT in accordance with system design and the TS. The licensee plans to document their technical review of this issue in their safety evaluation that will be performed to revise the UFSAR. This item is identified as fourth example of URI 50-275/97-202-05.

There is no installed instrumentation to measure chemical concentration in the SAT. Concentration is verified through chemical analysis under procedure C-1, "Spray Additive System Chemical Inventory."

In addition to teak level, spray additive flow indication (loop FT-930) is also provided in the main control room to monitor operation of the SAT. Level instrument calibration and setpoint data were determined under calculations TV-12-1, LT-12-2, "Spray Additive Tank 1-1 Level Channel 931Calibration," Rev. 1, and LT-12-5, "Spray Additive Tank Level Channel LIC-932 Calibration," Rev. 2. Channel uncertainty is determined by calculation J-54, "Nominal Setpoint Calculation for Selected PLS Setpoints," Rev.10. SAT flow calibration was determined under SC-M-12-F930, "Instrument Scaling Calculation Spray Additive Tank 1-1 to Eductors Channel FT-930," Rev.0. Based on a review of these calculations, the PIMS database and a verification of the instrument installation, the team found the SAT instrumentation to be adequate.

The team noted the following calculational discrepancy during review of the SAT instrumentation:

> Scaling Calculation SC-L-12-1, "Instrument Scaling Calculation Spray Additive Tank 1-1 to Eductors Flow Channel FT-930" appears to be redundant with Scaling Calculation SC-M-12-F930. Both calculations have the same title and similar results but no references or superseding notes are indicated in either caIc. Based on discussions with the licensee and as noted in another calculation (N-070), SC-M-12-F930 should replace SC-L-12-1. The licensee indicated that SC-L-12-1 will be deleted.

E1.3.3.3 Conclusions

The instrumentation and control design for the CS system was considered adequate. The above findings do not constitute any operability concern as all setpoints that wore reviewed have adequate margin and the technical specification limits are not exceeded. Discrepancies in the Post Accident Monitoring instrumentation were limited to documentation errors that do not affect the capability of the system. Weaknesses were observed in the UFSAR and calculations, specifically, in keeping these documents current and consistent with the as-built cosign.

E1.3.4 System Walkdown

E1.3.4.1 Scope

The team inspected the installed mechanical, electrical, and instrumentation and control equipment for the CS system to evaluate their consistency with drawings, design specifications, and regulatory requirements. During the walkdown the team interviewed plant system engineers,

and operations and maintenance personnel. The team's walkdowns covered the CS system pump rooms, control room, auxiliary shutdown panel, cable spreading room, switchgear rooms, battery rooms and electrical distribution panels.

E1.3.4.2 Findings

a. CS Pumps

The team noted boron accumulation in the pump seal leakage collection housings for the CS pumps. The outboard veal for pump 1-2 was recently replaced and there was a small amount of boron in the housing from the repair activity in addition to residue from expected minor shaft leakage during required surveillance runs. However, Pump's 1-1 outboard veal had more significant accumulation than typically expected. The licensee responded that pump 1-1 veal leakage was above the DCPP acceptable rate, and a seal replacement work order was in place to schedule the activity during the week of September 8, 1997. The seal collection housing material is stainless steel and minor accumulation of boron is acceptable. Some leakage and accumulation is expected when each pump is run for maintenance or surveillance. The seal was replaced during the inspection period. However, the new seal installation was incorrect and the pump area was sprayed with borated water. AR A0443429 documented the problem and facilitated rework. Subsequent testing verified acceptable seal performance. The AR's corrective actions included the need for a licensee review of the seal replacement maintenance work package to assure that future replacements will be acceptable without rework.

b. RWST Level Local Indication

During the plant walkdown of Area J, elevation 100', the team noticed the local RWST level indicator, Ll-964, reading at 98% level. The RWST instrumentation is designed to provide a high level alarm at 96% level. During a subsequent walkdown of the control room, no indication of a high level alarm condition was noted although local indicator Ll-964 had exceeded the setpoint. The licensee acknowledged that shore had been a similar condition in Unit 2, where a high alarm appeared inconsistent with indicated level due to instrument calibration tolerances overlapping as a result of operations requirement to maintain RWST level higher than normal. This condition had been addressed in AR A04279229, dated April 1997. This observation had no safety significance since there are redundant RG 1.97 RWST level indicators Fl-920, Fl-921, Fl-922 in the control room.

c. SAT Level Indication

The team noted that the SAT nitrogen pressure gage Pl-972 range was "-30 to +30" but had no units of measure. This gage is monitored daily on operator rounds to ensure a nitrogen blanket pressure on the SAT of 5 psig. The licensee responded that this gage, calibrated 30" vacuum to 30psig, was originally furnished with no units on the indicator scale by Westinghouse, although Vendor drawing DC 663230-119-8 PG. 9 shows a range of "30"-0-30#." It appears that plant operations is cognizant of this condition and considers the existing indicator acceptable.

d. Instrument Tubing

During a walkdown of the CS pump and SAT area, the team noted that the CS pump instrumentation tubing was not sloped properly or not provided with vent or drain valves.

Specifically, those instruments in question were pressure instruments Pl-933A, Pl-933B, Pl-933C and Pl-933D. Industry standards and DCPP's requirements are defined in DCM T-38, which provide design guidelines for instrument line slopes, vents and drains. In response, the licensee stated that this condition had been previously identified under AR A0265124 on a generic basis. Due to its generic impact, Engineering Report DVR 5W, dated 3/17/91 and Quality Evaluation QE Q0009595, dated 9/8/92, were initiated to perform detailed walkdowns to document and justify existing instrument tubing installations that deviated from DCM T-38. These reports evaluated
as-built installations which included deviations such as zero or negative tubing slopes, missing vents and drain valves, missing dips, and supports exceeding the required span. Based on a review of the reports, the team concluded that the issue was properly addressed.

e. RHR Heat Exchanger Flow Instrumentation

RHR heat exchanger CCW flow instrument loops F-85 and Fl-88 provide signals for flow indication and high/low flow alarms. The team noted that the high and low taps for these instrument loops are located on a pipe elbow in a vital CCW supply line. Since installation of taps on pipe elbows is not common practice, the team reviewed applicable calculations J-048, "Flow Element Pipe Elbow Type for Fls-85 and 88," Revision 2 and NSP-1-14-84, "RHR Heat Exchanger High CCW Flow Alarm Setpoint Uncertainty," Revision 0, to verify suitability of this type of configuration. Based on the team's review, the design is considered adequate for the intended function and accuracy of the instrument loops.

E1.3.5 Updated Safety Analysis Report

As a result of a review of the UFSAR, the team noted the following discrepancies:

- UFSAR Section 6.2.3.4.1, page 6.2-45, Component Testing, mentions provisions for testing SAT tank high pressure and low level alarms. The tank high pressure alarm does not exist in the l&C design.

- UFSAR Section 6.2.2.2.1, page 6.2-22, Containment Spray, describes the initiating signal for the CS system. The UFSAR description does not mention the role of the " S" signal in the CS actuation. As described in Chapter 7 of the UFSAR, DCM S-12, and various design documents, CS is actuated upon a coincident "S" and "P" signal.

- UFSAR Section 6.2.2.5, page 6.2-31, CS Instrumentation, describes the requirement for measuring containment spray nozzle flow. This section needs to be clarified since the existing instrument configuration can only measure nozzle flow when spraying from the CS pump but not from the RHR system.

These discrepancies have no safety impact. The issues involve inconsistencies in the UFSAR and various l&C design documents. ARs A0441540 and A0442684 were issued to initiate UFSAR and other design document corrections.

E1.4 Containment Fan Cooler System Design Review

E1.4.1 Mechanical

E1.4.1.1 Scope of Review

The team performed a design review inspection of the Containment Fan Cooler (CFC) system in support of the verification of DCPP's capability for heat removal to reduce containment pressures and temperatures following a LOCA or MSLB. For the mechanical design review of the CFC system safety functions following a design bases accident, and requirements for the system to support normal plant operations, the team evaluated DCPP's licensing and design basis documentation. The team reviewed UFSAR sections 6.2, 9.2.2, and 15.5.17 related to the CFC and CCW systems; Technical Specifications sections 3 and 4; DCM S-23A, Revision 4, Containment HVAC System; Portions of DCM S-14, Revision 2, CCW System as related to the CFC system; drawings; related calculations for both CFC and CCW systems; and operating, maintenance and surveillance procedures for verification of design in the functional performance of the components. The team additionally performed a review of the design change package for removal of the moisture separators and HEPA filters from the containment fan cooler unit (CFCU). The design change for the CCW surge tank over-pressurization to eliminate potential flashing in the CFCUs was also reviewed. The team participated in plant and equipment walkdowns, limited to system components supporting the CFCUs (no containment entries were made for this inspection).

E1.4.1.2 Findings

a. Verify CFCS Performance for Containment Pressure and Heat Removal

The team verified the capability of the CFCS to reduce the pressure and remove the heat generated in the containment due to a MSLB/LOCA and maintain containment integrity. The team determined that 2 CFCUs running at low speed with a minimum CCW flow of 1600 gpm through each cooler coil was adequate to maintain the containment integrity during MSLB/LOCA injection phase.

The limitation of the CFCS is that for long term post-LOCA cooling the coolers are able to transfer more heat than the CCW system can subsequently transfer to the UHS with only one CCW heat exchanger in operation and one ASW pump supplying cooling water at an ocean temperature of 64°F. Consequently, the number of fan coolers operating may have to be reduced to limit the total heat transferred during these specific postulated scenarios.

The team reviewed calculation HVAC 94-01, "Determine air flow rates for 5 CFCU's in low speed running in parallel," Revision 0, to verify the required air flow to the cooling coils for containment pressure and heat removal. This calculation determined that for minimum safeguards, two CFCUs balanced to a maximum flow of 114,000 CFM (57,000 CFM each) at low speed were required. For maximum safeguards to limit the CCW temperature rise within design limits, the air flow to each CFCU should be less than 54,000 CFM for-all five CFCUs running in parallel. This calculation was verified by the System Engineering Group by actual measurements of air flow rates. The results confirmed that the flow rates for all five fans were less than 54,000 cfm. The results determined that air flow from each CFCU would be 45,500 CFM if all five CFCU's were running in parallel. The data was collected under AR A0291998, AE-03. Surveillance STP M-93-A performs air flow

measurements each refueling outage and verifies that the actual air flow characteristics are not deteriorating over time.

In reviewing the various CFCU cooling coil calculations, the team identified that only the CCW internal fouling factor was considered in the Westinghouse analysis. Westinghouse in their WCAP analysis did not take any penalty for air-side cooler fouling conditions. The condensate film created during the event was taken as a penalty by Westinghouse. Westinghouse's contention is that any chemical accumulation on the coils will be washed away by the excessive volume of liquid condensing on the air-side of the coolers. Other foreign materials potentially entering the air plenums upstream of the coolers and possibly becoming a physical interference to flow through the coolers (debris fouling) was also not addressed by DCPP in any analysis. The potential for significant debris fouling was determined by the team to be unlikely because of the physical location of the coolers. All of the CFCUs and associated air inlet modules prior to the cooling coils are located on the operating elevation of containment. The equipment is all located outside of the primary missile shield wall. Debris loosened by the accident conditions is remote to this area and very unlikely to be transported to the area of the CFCUs. In reaching this conclusion the team took into consideration a recent event at DCPP where a small RCS leak of 0.02 gpm contributed to long term (about 7 months) flow of RCS products through the CFCU enclosures with no significant chemical accumulation on the cooler surfaces. The boron was washed off, as predicted, by condensation of the steam and was runoff into the drain system for the CFCUs. However, during scheduled maintenance of the CFCU's, it was identified that boron did precipitate and was deposited on the fan surfaces, fan enclosure, and to some extent on the downstream back-draft damper blades, but not on the coil surfaces. In response to the team's concern regarding performance of the fan and back-draft damper with boron accumulation, the licensee provided an evaluation which concluded that the CFCU's would perform their design required functions following an accident. A sensitivity analysis was performed by PG&E Engineering that indicated the CFCUs could allow a 10% decrease in performance due to external fouling and undefined degradation of the system with only a 1.5 psi containment peak pressure post-accident increase. The margin without this system degradation is 4.8 psi. The team reviewed the analysis and found it acceptable.

b. Effect of CFCU Reverse Rotation on Electrical Protection Devices

The team reviewed the effect of reverse rotation of the fans in the CFCU on the mechanical and structural integrity of the fans and duct work and the motor protection circuit. DCPP has experienced problems with the back-draft dampers that causes reverse rotation of the fans to speeds as high as 170 rpm. The problems have been caused by the dampers being stuck in the open position due to linkage assembly problems or one of the blades being partially open when the damper should have been fully closed. The back-draft dampers have essentially been provided to protect the CFCU fan and motors from potential adverse effects of back pressure
(7.0 psid) during a LOCA when the lower containment volume where the CFCU ductwork discharges would pressurize more than the upper containment volume from where the CFCUs take intake.

Based on the team's review of Westinghouse's analysis PCE-92 0057, "Summary of Back draft Damper Problem Evaluation," Rev. 0 and DCPP calculation 205A-DC, "Evaluation of Reverse Rotation of CFCU on Electrical Protection System," Rev 0, the team concluded that the failure of the back draft dampers leading to reverse rotation of the fans would not have prevented the CFCUs from performing their safety function for the following reasons:

- The fans used in the DCPP's CFCUs were subjected to higher back pressure in a test performed by Westinghouse which showed that a back pressure of 9.0 psid had no significant effect on the mechanical integrity of the fan.
- The flow area through the damper is relatively small compared to the duct, coils, inlet dampers etc., such that there will be a large pressure drop across the damper and the pressure differential between the inside and outside of the CFCU enclosure will be about 0.7 psid which is loss than the rated 3 psid. The back pressure will, therefore, have no effect on the structural integrity of the CFCUs.
- The maximum reverse speed caused due to back draft from which the fans could be started at a reduced voltage of 85% at low speed is 400 rpm. To prevent any undesirable tripping of breaker and thermal overload relay in the motor control circuit when starting motors with fans in reverse rotation, DCPP has replaced the breakers and thermal overload relays with higher magnetic trip rating breakers and slow trip typo thermal overload relays. For high speed, the maximum reverse speed from which the fans can be started is
120 rpm.

The licensee has identified some equipment failures in the counterweights and shaft pin designs for the back draft dampers. Maintenance and repairs to the dampers have been performed. The team's review of the mandatory periodic preventive maintenance determined that this has resulted in improved performance of the damper assemblies, thus minimizing/eliminating CFCU fan reverse rotation.

c. Vendor Technical Manual (DC 663079-51-15) Discrepancies

The team reviewed the Vendor Technical Manual (VTM) for the CFCUs to verify existing design with the requirements in the VTM. Some discrepancies were identified. A "Special Instructions" section in the VTM identified the requirement for a water trap to be installed in the drain line from the CFCU combined motor cooler coil housing and environment protection enclosure. The trap would assure that no back leakage could enter the enclosure. This motor enclosure was stated in the VTM as required to protect the motor from the accident environment during and following an event. The EQ documents reviewed indicated the same requirement. Drawings for the motor cooler drain lines did not indicate the water traps as installed. The licensee verified that the traps were not installed and during the inspection, received confirmation from Westinghouse that the traps were not required. AR 0441408 was initiated to revise the VTM.

A typo in the text Sections 1.3.4 and 1.3.5 of the VTM describing the cooling coils tubing wall thickness as 0.035" and 0.35" was identified by the team. AR A0443446 was initiated to correct the number to 0.035" for coil tubing wall thickness descriptions. This AR also requires that the EQ documentation be revised to state that a completely sealed enclosure is not essential for environmental qualification.

E1.4.1.3 Conclusions

The team concluded that the CFCU system is being operated within the design and licensing requirements and can meet the plant accident and normal heat removal requirements in transferring heat to the CCW system.

The attributes reviewed have identified that the CFCU design requirements for containment heat removal are being maintained. Plant modifications to the system have not compromised the system's capability to perform the safety functions required by plant design.

The limitation of the CFCU system is that the coolers are able to transfer more heat than the CCW system can subsequently transfer to the ultimate heat sink in specific accident scenarios. Consequently, the number of fan coolers operating may have to be reduced to limit the total heat rate transferred during these specific postulated scenarios. The Technical Support Center will determine CFCU operating requirements under events when the CCW design limits may be exceeded. Safety does not appear compromised by this option for operation - the only effect is that the time required to reduce containment pressures and temperatures to ambient conditions following an accident will be extended.

E1.4.2 Electrical

The electrical discussion in Section E1.2.2 of this report covers the electrical design review of the CFC system.

E1.4.3 Instrumentation and Control

E1.4.3.1 Scope of Review

The scope of the instrumentation and control design assessment consisted of a review of the CFCU system design and associated documents. Interfacing portions of the CCW system were also reviewed. Documents that were reviewed included Chapters 6 and 7 of the UFSAR, Technical Specifications, design criteria memorandum, piping and instrument schematics, electrical schematics, logic diagrams, 3 calculations, PIMS database, 1 surveillance procedure and 1 operating procedure. System walkdowns and interviews with plant personnel were also conducted to verify as-built design.

E1.4.3.2 Findings

The system design documents reviewed by the team adequately supported the design bases, except for the items discussed in the following paragraphs:

a. CFCU RG 1.97 Instrumentation

UFSAR Section 7.5, Table 7.56 DCM T-24, and letter DCL 93-284 provide the design bases for the CFCU RG 1.97 instrumentation. Required instrumentation consists control room indication of containment atmosphere temperature, containment sump water temperature indication, and operating status for each CFCU.

Two redundant containment atmosphere temperature indicators (loops TE-940 and TE-941) are provided on main control room panel PAM1. Two redundant containment sump temperature indicators (loops TE-942 and TE-943) are also located on panel PAM1. RG 1.97 lists these instrument loops as Type D, Cat. 2, variables with standby power source. Based on the team's review of DCM T-24, uncertainty calculation PAM-0-0-001, design documents and as-built condition, both the containment atmosphere and sump water temperature indicators were designed in accordance with RG 1.97. A review of the logic diagrams, schematics and panel layout also confirmed that speed indicating lights, and motor ammeters to monitor CFCU operating status were provided in the design in accordance with the RG.

b. CFCU/CCW Instrument Loop Accuracy and Scaling Calculations

The team reviewed the setpoint methodology and uncertainty calculations for the following instrument loops to verify that adequate tolerance for instrument error has been incorporated in the CFCU design:

1. SGM-14-F70, "Instrument Scaling Calculation Containment Fan Coolers Flow Channels FT70, FT-71, FT-72, FT-73 and FT-74," Revision 1.

2. PAM-0-14-070, Determination of Indication Uncertainty of CFCU CCW Flow," Revision 1.

The team determined that the above calculations adequately supported the instrument design.

E1.4.3.3 Conclusions

The instrumentation and control design for the CFCU system was considered adequate. There were no findings that would constitute operability concerns or require further followup.

E1.4.4 System Walkdown

CFCU System Instrumentation Walkdown.

The team's walkdown of the control room for the CS system as discussed in Section E1.3.3.4 also included a verification of the as-installed RG 1.97 instrumentation for the CFCU system, which includes containment atmosphere and sump water temperature indicators, motor, ammeters and speed status lights for each CFCU. As part of the CFCU l&C verification, the team also walked down the penetration area to verify the CFCU/CCW coil outlet flow transmitters and local temperature indicators. Instrument ranges, locations, and method of identification and installation design were reviewed against the UFSAR, DCM T-24 and design documents. As a result of the walkdowns, the team concluded that the installed instrumentation is in accordance with the design and RG 1.97.

Xl Exit Meeting

After completing the on-site inspection, the team conducted an exit meeting with the licensee on September 11, 1997, that was open to public observation. During the exit meeting, the team leader presented the results of the inspection. A partial list of persons who attended the exit meeting is contained in Appendix B. Proprietary material was reviewed during this inspection but this report contains no proprietary information

Appendix A

List of Open Items

This report categorizes the inspection findings as unresolved items (URls) and inspection followup items (IFI) in accordance with Chapter 610 of the NRC Inspection Manual. A URI is a matter about which the Commission requires more information to determine whether the issue in question is acceptable or constitutes a deviation, nonconformance, or violation. The NRC may issue enforcement action resulting from its review of the identified URls. By contrast, an IFI is a matter that requires further inspection because of a potential problem, because specific licensee or NRC action is pending, or because additional information is needed that was not available at the time of the inspection.

Item Number	**Finding Type**	**Title**
50-275/97-201-01	IFI	Review of UHS Calculation for Maximum UHS Temperature at Which the Plant can be Operated Without Exceeding ASW system Design Limits (Section E1.2.2.2.c)
50-275/97-201-02	IFI	Review of Revision to WCAP-14282 and incorporation of revised WCAP-14282 into design bases documentation (Section E1.2.2.2.c)
50-275/97-201-03	URI	Determine if Long-term post-LOCA Operation of ASW System With Both Trains Tied Together Represents a USQ (Section E1.2.2.2.d)
50-275/97-201-04		IFI ASME Section Xl testing of ASW pumps (Section E1.2.2.2.f)
50-275/97-201-05	URI	Discrepancy in Design Documentation (Sections E1.2 2.g, E1.2.4.2.e, E1.3.3.2.a, E1.3.3.2.d
50-275/97-201-06	URI	Availability of an Alternate Flowpath for the ASW System Section (Section E1.2.2.2.h)
50-275/97-201-07	URI	EDG transient analysis computer simulation study (Section E1.2.3.2.a)
50-275/97-201-08	IFI	Control of Calculations (Section E1.2.3.2.c, E1.2.3.2.i)
50-275/97-201-09	IFI	Review of Battery Charger Settings (Section E1.2.3.2.d)

Appendix A

List of Open Items

This report categorizes the inspection findings as unresolved items (URls) and inspection followup items (IFI) in accordance with Chapter 610 of the NRC Inspection Manual. A URI is a matter about which the Commission requires more information to determine whether the issue in question is acceptable or constitutes a deviation, nonconformance, or violation. The NRC may issue enforcement action resulting from its review of the identified URls. By contrast, an IFI is a matter that requires further inspection because of a potential problem, because specific licensee or NRC action is pending, or because additional information is needed that was not available at the time of the inspection.

Item Number	**Finding Type**	**Title**
50-275/97-201-01	IFI	Review of UHS Calculation for Maximum UHS Temperature at Which the Plant can be Operated Without Exceeding ASW system Design Limits (Section E1.2.1.2.c)
50-275/97-201-02	IFI	Review of Revision to WCAP-14282 and incorporation of revised WCAP-14282 into design bases documentation (Section E1.2.1.2.c.2)
50-275/97-201-03	URI	Determine if Long-term post-LOCA Operation of ASW System With Both Trains Tied Together Represents a USQ (Section E1.2.1.2.d)
50-275/97-201-04	IFI	ASME Section Xl testing of ASW pumps (Section E1.2.1.2.f)
50-275/97-201-05	URI	Discrepancy in Design Documentation (Sections E1.2. 1.2.9, E1.2.3.2.e, E1.3.3.2.a, E1.3.3.2.d
50-275/97-201-06	URI	Availability of an Alternate Flowpath for the ASW System Section (Section E1.2.1.2.h)
50-275/97-201-07	URI	EDG transient analysis computer simulation study (Section E1.2.2.2.a)
50-275/97-201-08	IFI	Control of Calculations (Section E1.2.2.2.c, E1.2.2.2.i)
50-275/97-201-09	IFI	Review of Battery Charger Settings (Section E1.2.2.2.d)

Item Number	Finding Type	Title
50-275/97-201-10	URI	Potential USQ and TS Adherence Associated with Containment Spray During Containment Recirculation (Section E1.3.1.2.b & c)

Appendix B

Exit Meeting Attendees

NAME	ORGANIZATION
D. Allen	NRC, Resident Inspector
S. Bloom	NRC, Project Manager, NRR/DRPE
D. Brosnan	PG&E, Supervisor, Nuclear Safety Assessment and Licensing (NSAL)
R. Berger	PG8E, NSAL, Containment Design Engineer
D. Chamberlain	NRC, Deputy Director, DRS/Region IV
K. Herman	PG&E, DES, Supervisor of Electrical Design
J. Kelly	PG&E, DES, Mechanical Engineer
S. Ketelsen	PG&E, NSAL, Supervisor Nuclear lnterface
D. Norkin	NRC, Section Chief, NRR/PSIB
B. Powers	PG&E, Vice President and Plant Manager
G. Rueger	PG&E, Senior Vice President and General Manager
J. Skaggs	PO&E, Operation Department
M. Smith	PG&E, DES, Supervisor Nuclear Design
T. Stetka	NRC, Branch Chief, DRS/Region IV
D. Tateosian	PG&E, Manager Design Engineering Services (DES)
J. Taylor	Westinghouse, PG&E Representative
R. Webb	PG&E, DES, Director of Technical Support
L. Womack	PG&E, Vice President and Manager of Nuclear Tech Services

Appendix C

List of Acronyms

AB	Auxiliary Building
AC	Alternating Current
ANSI	American National Standard Institute
AOV	Air-Operated Valve
AR	Action Request
ASME	American Society of Mechanical Engineers
ASW	Auxiliary Saltwater
AUX S/D	Auxiliary Shutdown
AUX	Auxiliary
AUX S/D PNL.	Auxiliary Shutdown Panel
BTU	British Thermal Unit
CCW	Component Cooling Water
CFCS	Containment Fan Cooler System
CFCU	Containment Fan Cooler Unit
CFM	Cubic Feet per Minute
CFR	Code of Federal Regulations
CS	Containment Spray
CTMT	Containment
CV	Control Valve
DBA	Design Base Accident
DBD	Design Basis Documentation
DC	Direct Current
DCM	Design Criteria Memorandum
DCN	Drawing Change Notice
DCR	Document Change Request
DCPP	Diablo Canyon Power Plant
DP	Differential Pressure
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EQ	Environmental Qualification
ESF	Engineered Safety Features
ESFAS	Engineered Safety Features Actuation System
F	Fahrenheit
FCN	Field Change Notice

FCR	Facility Change Request
FCV	Flow Control Valve
ft., FT	Feet or Foot
FW	Feed Water
gal., GAL	Gallons
gpm., GPM	Gallons Per Minute
HELB	High Energy Line Break
HEPA	High Efficiency Particulate Air
HS	Hand Switch
HVAC	Heating, Ventilating, and Air Conditioning
HZ, Hz	Hertz
I&C	Instruments and Control
IFI	Inspection Follow-up Item
IN	Information Notice
ISI	In Service Inspection
IST	In Service Testing
kVA	Kilovolt-Ampere
LAR	License Amendment Request
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss-of-Coolant Accident
LOOP	Loss-of-Offsite Power
M/HELB	Moderate/High Energy Line Break
M&TE	Measuring and Test Equipment
MCB	Main Control Board
MCC	Motor Control Center
MF	Main Feedwater
MOV	Motor Operated Valve
MSLB	Main Steam Line Break
MP	Maintenance Procedure
NaOH	Sodium Hydroxide
NC	Normally Closed
NNI	Non-Nuclear Instrumentation
NNS	Non-Nuclear Safety
NO	Normally Open
NPSH	Net Positive Section Head
NRC	Nuclear Regulatory Commission
NSR	Nuclear Safety Related
NSSS	Nuclear Steam Supply System

OE	Operability Evaluation
P&1D	Piping & Instrumentation Diagram
PAM	Post Accident Monitoring
PEP	Plant Engineering Procedure
PG&E	Pacific Gas & Electric
Pl	Pressure Indicator
PIC	Pressure Indicator Controller
PM	Preventive Maintenance
PMT	Post Maintenance Testing
PMWO	Preventive Maintenance Work Order
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Assessment
psi, PSI	Pounds per Square Inch
psia, PSIA	Pounds per Square Inch Absolute
psid, PSID	Pounds per Square Inch Differential
psig, PSIG	Pounds per Square Inch Gauge
PT	Pressure Transmitter
PVC	Polyvinyl Chloride
QA	Quality Assurance
RB	Reactor Building
RC	Reactor Coolant
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
RHR	Residual Heat Removal
RPS	Reactor Protection System
RWST	Refueling Water Storage Tank
RV	Reactor Vessel
S&L	Sargent & Lundy
S\D	Shutdown
SA	Safety Actuation
SAT	Spray Additive Tank
SCFM	Standard Cubic Feet per Minute
SE	Safety Evaluation
SEC	Seconds
SECL	Safety Evaluation Check List
SER	Safety Evaluation Report
SFAS	Safety Features Actuation System
Sl	Safety Injection

SOV, SV	Solenoid Operated Valve
SPDS	Safety Parameter Display System
SPEC	Specification
SSFI	Safety System Functional Inspection
SSPS	Solid State Protection System
STP	Surveillance Test Procedure
TCV	Temperature Control Valve
TDH	Total Developed Head
TR	Temperature Recorder
TS, Tech. Spec.	Technical Specifications
TSC	Technical Support Center
TT	Temperature Transmitter
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
UPS	Uninterruptible Power Supply
URI	Unresolved Item
USQ	Unreviewed Safety Question
V DC, VDC	Volts DC
V AC, VAC	Volts AC
W	Watts
WCAP	Westinghouse Containment Analysis Program

UNITED STATES
NUCLEAR REGULATORY COMMISION

REGION IV

611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011~064

April 17, 1997

Mr. Gregory M. Rueger, Senior Vice President
and General Manager
Pacific Gas and Electric Company
Nuclear Power Generation N9B
P. O. Box 770000
San Francisco California 94177

SUBJECT: NRC INSPECTION REPORT 50-275/98-05; 50-323/98-05

Dear Mr. Rueger:

From February 2-6 and 23-27, 1998, an engineering followup inspection was conducted at your Diablo Canyon Nuclear Power Plant, Units 1 and 2, reactor facilities. Following the onsite inspection period, you provided additional details related to several issues identified during the inspection. The inspection was concluded on March 18,1998. The enclosed report presents the scope and results of that inspection.

The inspection focused on resolution of previous NRC Inspection findings and included a review of those issues identified during an architect/engineering inspection documented in NRC Inspection Report 50-275;-323/97-202. Within that report, two issues were discussed that appeared to involve unreviewed safety questions, though they were not processed as such under the provisions of 10 CFR 50.59. These issues remain unresolved and will be addressed during a future inspection.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response will be placed in the NRC Public Document Room (PDR).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/s/ Thomas F. Stetka, Acting Chief
Engineering Branch
Division of Reactor Safety

Docket Nos.: 50-275; 50-323
License Nos.: DPR-80; DPR-82

Enclosure:
NRC Inspection Report
50/275/98-05; 50-232/98-05

cc w/enclosure:
Dr. Richard Ferguson
Energy Chair
Sierra Club California
1100 11th Street, Suite 311
Sacramento, Califomia 95814

Ms. Nancy Culver
San Luis Obispo Mothers for Peace
P.O. Box 164
Pismo Beach, Califomia 93448

Chairman
San Luis Obispo County Board of
Supervisors
Room 370
County Government Center
San Luis Obispo, California 93408

Mr. Truman Burns/Mr. Robert Kinosian
California Public Utilities Commission
505 Van Ness, Rm. 4102
San Francisco, California 94102

Robert R. Wellington, Esq.
Legal Counsel
Diablo Canyon Independent Safety Committee
857 Cass Street, Suite D
Monterey, Califomia 93940

Mr. Steve Hsu
Radiologic Health Branch
State Department of Health Services
P.O. Box 942732
Sacramento, California 94234

Christopher J. Wamer, Esq.
Pacific Gas and Electric Company
P.O. Box 7442
San Francisco, Califomia 94120

Robert P. Powers, Vice President
and Plant Manager
Diablo Canyon Power Plant
P.O. Box 56
Avila Beach, California 93424

Managing Editor
Telegram-Tribune
1321 Johnson Avenue
P.O. Box 112
San Luis Obispo, California 93406

ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-275; 50-323
License Nos.:	DPR-80; DPR-82
Report No.:	50-275/98-05; 50-323/98-05
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Nuclear Power Plant, Units 1 and 2
Location:	7 1/2 miles NW of Avila Beach Avila Beach, California
Dates:	February 2-6 and 23-27, and March 2-18,1998
Inspectors:	M. Runyan, Reactor Inspector, Engineering Branch P. Goldberg, Reactor Inspector, Engineering Branch D. Pereira, Reactor Inspector, Engineering Branch
Accompanying Personnel:	D. Prevatte, Consultant
Approved By:	T. Stetka, Acting Chief, Engineering Branch Division of Reactor Safety

ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Diablo Canyon Nuclear Power Plant, Units 1 and 2
NRC Inspection Report 50-275/98-05; 50-323/98-05

Engineering

- The deletion of procedural steps to separate trains of the auxiliary saltwater and component cooling water systems, when transferring to hot leg injection during a loss of coolant accident recovery appeared to constitute an unreviewed safety question. This unresolved item was left open pending additional review by the NRC (Section E8.14).

- The design of the auxiliary saltwater system appeared vulnerable to common-mode failure from two mechanisms: (1) failure of the intake screen shared by both trains of auxiliary saltwater could clog both auxiliary saltwater heat exchangers, resulting in a loss of component cooling water, and (2) because both Units 1 and 2 auxiliary saltwater intake structures are located in close proximity, both screens could be clogged at the same time, preventing the intended design that one unit provide an auxiliary suction source for the other unit. The licensee's current design met the licensing basis (Section E8.17).

- The discovery of a design vulnerability that could result in loss of containment spray during the recirculation phase (of a loss of coolant accident recovery) appeared to constitute an unreviewed safety question. This unresolved item was left open pending additional review by the NRC (Section E8.21).

Report Details

Summary of Plant Status

During the first week of the inspection, both Units 1 and 2 were operating at full power. During the second week of the inspection, Unit 1 was operating at full power and Unit 2 was shutdown for a refueling outage.

III. Engineering

E8 Miscellaneous Engineering Issues (93902)

E8.01 (Closed) Inspection Followup Item 50-275/9517-01: Design of the 4kV to 480V Safety-Related Transformer

Background

This item involved two issues concerning electrical transformers. The first involved the method used to brace the coils in the unit auxiliary transformers, which appeared to allow for relaxation over time resulting in a reduced capability to withstand faults. The second was to followup on the licensee's design review of the 4kV to 480V transformers to determine if a similar vulnerability existed.

Inspection Followup

The inspectors discussed these issues with licensee engineers and reviewed an internal report entitled, "Short-Circuit Evaluation of Diablo Canyon Transformers," dated June 21, 1996. The report documented an effort to evaluate the capability of all Diablo Canyon transformers to withstand a short circuit.

The licensee replaced the unit auxiliary transformers with rebuilt transformers of a different type. The original units were manufactured by Wagner. The Wagner transformer on Unit 1 failed catastrophically when subjected to a through fault on October 21, 1995. The replacement transformers were rebuilt General Electric transformers. A review by the licensee indicated that the withstand stress for the rebuilt transformers was at least two times greater that the calculated stress corresponding to a through fault. For the Wagner transformers, the withstand stress was calculated to be only 60 percent of the through-fault stress. Therefore, the replacement transformers provided a substantial increase in fault survivability margin.

The 4 kV to 480 V transformers at Diablo Canyon are dry-type transformers for which design records were not available. In lieu of a design study, the licensee performed a sample inspection. Based on historical records, the licensee concluded that these type of transformers rarely fail and when they do fail, a prior inspection would likely detect the incipient failure. The dry-type transformers are routinely inspected and cleaned. The only defect suggesting an impending fault-stress problem was found in 1991 and involved a cracked pressure block on top of the coils of one of the dry-type transformers. The blocks were replaced. Following this discovery, all other dry-type transformers were inspected for this defect and no additional problems were found. Based on these results and the continuing inspection of these units, the licensee determined that the 4kV to 480V transformers were not subject to the same failure mode experienced by the Unit 1 auxiliary transformer.

Based on review of this information and discussions with licensee engineers, the inspectors concluded that the licensee's response to this issue was adequate.

E8.02 (Closed) Deviation 50-275/9612-01: NRC Not Informed of the Licensee Decision to Not Determine the Mean Seat Areas For All 20 Unit 1 Main Steam Safety Valves

Background

In 1994, the licensee conducted a program to test the main steam safety valves at the Westinghouse Service Center using both live steam and an AVK device. The licensee found that there was good correlation between the set points measured on live steam and the AVK device. In licensee Letter DCL-95-241, dated November 1, 1995, to the NRC, the licensee committed to perform additional testing during the Refueling Outages 1 R7 and 2R7 for Units 1 and 2. This testing was to determine the mean seat area for the AVK device for all 20 of the main steam safety valves.

Due to equipment problems at the test facility and the licensee's decision to not delay the refueling outage, specific mean seat areas were developed for only 9 of the 20 main steam safety valves. The licensee did not inform the NRC of the failure to fully meet the commitment until after plant restart from the Unit 1 Refueling Outage 1R7.

Inspection Followup

The inspectors reviewed the licensee's corrective actions for the failure to meet their commitment. The licensee stated that they appointed a project manager to specifically manage the main steam safety valve augmented test program. The inspectors interviewed the project manager and found the project manager was very knowledgeable of the valves and the test program. In addition, the inspectors found that the licensee was no longer using the AVK test equipment and associated mean seat areas for testing the main steam safety valves. The licensee was testing the valves with Trevitest equipment. Due to the change in test equipment, the inspectors concluded that the licensee's commitment was no longer applicable.

E8.03 (Closed) Violation 50-323/9613-01: Failure to Have Adequate Fire Protection Material Control

Background

The NRC identified approximately 300 feet of 3-inch diameter combustible rubber hose stored in the containment penetration area of Unit 2. The hose was found at the 100-foot elevation in the auxiliary building with no transient combustible permit. Licensee Procedure OM8.1D4, “Control of Combustible Materials," Revision 3, paragraph 5.8.1 required that all combustible materials stored in an auxiliary building area, not designated for storage, receive a transient combustible permit.

Inspection Followup

In 1988, the licensee installed piping, dedicated hose connections, and storage hangers for approximately 300 feet of 3-inch flexible hose to perform steam generator rapid fill and drain down during refueling outages. This design change was not identified to require an impact review by fire protection personnel for changes to the fire protection program combustible loading calculations.

During 1988, the licensee performed a baseline fire protection area walkdown to identify and quantify insitu and transient combustible material. The licensee believed that the fire area walkdown was performed prior to the installation of the flexible hose, or, if it was installed at that time, that walkdown personnel assumed the hose would be removed upon completion of the refueling outage. Therefore, the 1988 baseline combustible material inventory did not identify the 300 feet of hose for inclusion in the engineering fire loading calculation.

The inspectors reviewed the licensee's completed corrective actions to prevent recurrence of the violation. These specific corrective actions included the removal of some combustible materials, or, where not removed, the issuance of transient combustible permits. In addition, the licensee performed the following actions to support the control of combustible materials:

1. Procedure OM8.1D4, "Control of Flammable and Combustible Materials," Revision 5, was revised on March 18,1997, to require periodic combustible material walkdowns by plant fire protection personnel and documentation of the results.

2. A licensee assessment to identify any additional insitu combustible materials in areas governed by Procedure OM8.ID4 was performed during the week of June 18, 1996. The additional insitu combustible materials identified during this assessment, which were all temporarily stored materials, were included in a revision of Calculation M-824, “Fire Loading Calculation," Revision 8. Permits were issued to identify this material as transient combustible.

3. Procedure CF3.1D13, Replacement or New Part Evaluation (RPE)," Revision 4, was changed on December 5,1996, to include a reference to Procedure CF3.1D9, "Design Change Package Development," Revision 6A, to ensure a review by the fire protection group.

The inspectors reviewed the corrective actions and concluded that they appeared to be appropriate to prevent recurrence of the violation. The inspectors reviewed revised Procedure OM8.1D4 and the revised Fire Loading calculation (M-824) for both units and determined that the completed corrective actions should prevent a similar occurrence.

E8.04 (Closed) Inspection Followup Item 50-275:-323/9613-02: Review of Auxiliary Saltwater System Piping Following Design Basis Seismic Event

Background

The licensee initiated a corrosion testing program in 1995 to quantify the condition of the auxiliary saltwater system piping. The testing determined that there was a potential for excessive corrosion on the Unit 1 piping located in the tidal zone near the plant's intake structure. The NRC noted that the piping was coated with fiberglass and epoxy, which had a projected life of 20 to 25 years, and the licensee's tests determined that the corrosion rate in the tidal area could be as high as 40 mils per year. The auxiliary saltwater system piping located outside of the tidal zone had a corrosion rate of 2 to 4 mils per year. The pipe was buried in 1971 and had a nominal pipe-wall thickness was 375 mils. Based on this information, the NRC determined that if the coating failed after 20 years of service (in 1991), that in 1996 (the year this issue was identified) the portion of the pipe exposed to corrosive conditions of 40 mils per year could have a pipe-wall thickness as low as 175 mils. The licensee performed an evaluation and determined that 188 mils was the minimum pipe thickness needed to survive a design basis seismic event. The NRC concluded that further information was needed to determine if the auxiliary saltwater system piping would remain functional following a design basis seismic event.

Inspection Followup

The inspectors discussed these issues with the licensee. In March 1997, the licensee installed piping to completely bypass the piping in the tidal zone. The licensee planned the same modification for Unit 2 in March 1998. The length of pipe in the tidal zone was only about 5 percent of the total length of auxiliary saltwater system piping.

The inspectors reviewed Design Change Package DCP C-049207, "Auxiliary Saltwater System Bypass Piping Intake to Hillside Vault," Revision 7, which provided the plans to bypass the auxiliary saltwater system piping within the tidal zone. The inspectors noted that the new bypass piping did not extend through the tidal zone. The sections of pipe that were bypassed were abandoned in place. The licensee provided cathodic protection for the buried portions of the bypass piping and the existing portion of the buried auxiliary saltwater system pipe. The inspectors determined that the licensee had adequately resolved the corrosion problem and that the concern of the effects of piping corrosion on the ability of the piping to withstand a seismic event was no longer an issue.

E8.05 (Closed) Violation 50-275:-323/9623-07: Plant Staff Review Committee did not Review Safety Evaluations as Required by Technical Specifications

Background

The NRC determined that as of October 23,1996, safety evaluations were performed for the core reloads for Unit 1, Cycle 8, and Unit 2, Cycles 7 and 8, without plant staff review committee (PSRC) evaluation review. In addition, fuel sipping was performed during the Unit 2 Refueling Outage 2R7 without the PSRC having reviewed the associated safety evaluation.

Inspection Followup

Westinghouse Electric Corporation (Westinghouse) prepared the 10 CFR 50.59 safety evaluations for Units 1 and 2 core reloads and for the Unit 2 fuel sipping modification. The Westinghouse safety evaluations concluded that the core reloads and the fuel sipping modification did not create unreviewed safety questions nor require changes to the technical specification.

Licensee engineering personnel used the Westinghouse safety evaluations, in part, as a basis for responding to questions contained in the safety evaluation screenings required by their administrative procedures. Because all screening questions had negative responses, the procedures did not require that licensing basis impact evaluations (LBIEs) be prepared and, as a result, a PSRC review was not required.

The licensee determined that the Westinghouse safety evaluations were not reviewed by the PSRC due to a programmatic deficiency in the procedures governing the LBIE program. Both the procedures and the training program for LBIEs did not contain specific requirements for processing safety evaluations provided by vendors. Licensee personnel were unaware that these safety evaluations were required to be reviewed by the PSRC.

The licensee took the following actions to prevent recurrence:

1. The PSRC reviewed the Westinghouse core reload and fuel sipping safety evaluations and agreed with the conclusions stated in the plant's safety evaluation screens. The core reloads and fuel sipping modifications did not result in any unreviewed safety questions or changes to the technical specifications. The PSRC met on October 24, 1996, and December 27, 1997, for core reloads and fuel sipping evaluation approvals, respectively.

2. The engineering staff was questioned as to whether the PSRC had reviewed any vendor safety evaluations that support current operation of the units. As of February 14, 1997, no other vendor safety evaluations supporting current operability of the units had been identified.

3. The applicable safety evaluation procedures were revised to clarify requirements regarding PSRC review of safety evaluations provided by vendors. Revision 3 to Administrative Procedure TS3.1D2, "Licensing Basis Impact Evaluations," was reviewed and approved by PSRC on June 6, 1997. Paragraph 5.1.11 stated that if a vendor develops a 10 CFR 50.59 safety evaluation for a licensee activity or analysis, then that safety evaluation shall be reviewed by the PSRC and an LBIE shall be generated to reference the vendor safety evaluation and to document PSRC review.

4. Licensee personnel were notified of changes to Procedure TS3.ID2. The licensee notified appropriate personnel via an e-mail message on July 29, 1997, stating that provisions had been added to help assure that vendor-developed safety evaluations are reviewed by PSRC.

5. The licensee stated that the Procedure TS3.1D2 changes were reviewed by each technical staff supervisor with his/her group in technical staff update sessions. These sessions were completed on August 1, 1997.

The inspectors reviewed the licensee's corrective actions, including revised Procedure TS3.ID2, the e-mail message, and technical staff update session documentation, and concluded that the licensee had taken adequate actions for this problem.

E8.06 (Closed) Violation 50-323/9624-03: Failure to Perform a 50.59 Evaluation Prior to Changing Unit 2 Reactor Trip Set Points.

Background

The NRC identified that on May 21, 1996, the licensee's PSRC approved increasing the Unit 2 reactor coolant low flow trip set point in Technical Specification 2.2.1, Table 2.2-1 without a written safety evaluation to determine whether this change involved an unreviewed safety question.

Inspection Followup

Engineering personnel performed a detailed analysis to provide a technical basis for the change in the reactor coolant system low flow trip set point. A LBIE screen was prepared, rather than a formal safety evaluation, prior to implementing the change. The LBIE screen was reviewed and approved by the PSRC in support of a technical specification interpretation (TSI) to administratively change the set point consistent with supporting analyses.

At that time, the licensee's procedure for processing TSIs did not require the performance of a 10 CFR 50.59 safety evaluation.

The licensee stated that the nuclear industry now has heightened sensitivity to the need to perform documented 10 CFR 50.59 safety evaluations of potential changes to the plant licensing bases. Based on this heightened sensitivity, the licensee concluded that a formal 10 CFR 50.59 safety evaluation should have been performed to satisfy this requirement.

The inspection team reviewed the licensee's completed corrective actions to prevent recurrence of the violation. These specific corrective actions included the following:

1. The method of measuring reactor coolant system flow was changed to require the measurement to be made at the beginning of each operating cycle, reducing instrument uncertainty. Because it was no longer necessary, the TSI was rescinded on November 7, 1996.

2. The existing TSIs were reviewed to identify which TSI should be: (1) included in the licensee's standardized technical specification submittal, (2) incorporated into the technical specification via a separate license amendment request, or (3) deleted. Based on current procedures, TSIs fitting Categories (1) or (2) would require a safety evaluation.

3. Procedure XI3.1D3, "Technical Specification Interpretations," Revision 3, was revised to require that when a TSI was submitted to the PSRC, a schedule for performing a confirmatory evaluation was included. The schedule provided for development and approval of either a technical specification bases change with an associated 10 CFR 50.59 safety evaluation, or a license amendment request.

The inspectors reviewed the list of TSIs (39 total) at the time of this inspection. Based upon the revised review process, the inspectors determined that 4 TSIs were being deleted, 14 TSIs were being incorporated into the technical specifications via a license amendment request, and the remaining 21 TSIs were being included in the licensee's standardized technical specification submittal.

Based upon the above completed corrective actions, the inspectors concluded that the licensee's actions should prevent recurrence of the violation.

E8.07 (Closed) Licensee Event Report 50-323/96-007: Technical Specification 3.7.1.1 Not Met Due to High Initial Main Steam Safety Valve Lift Points

Background

In August 1996, with Unit 2 in Mode 1 at 100 percent power, Technical Specification 3.7.1.1 was not met when 7 of the 20 main steam safety valves did not meet the technical specification tolerance for as-found set points. The licensee analyzed the high set points and determined that the set points were outside the technical specification tolerance, but not outside the design basis analytical margin. The licensee thought the cause of the high initial lifts was related to a sticking phenomenon between the main steam safety valve disk and nozzle seating surface. The licensee tested the main steam safety valves in place using the AVK hydraulic lift device. The licensee performed the testing as part of their augmented test program to identify the reason for the high initial lifts and the set pressure drifts that the plant had experienced.

The licensee performed a root cause analysis that lead the licensee to believe that the sticking phenomenon was caused by micro-bonding of gauled material originating from the relative motion of the disk against the nozzle seat. The licensee stated that laboratory tests indicated that gauling occurred during uncontrolled cooling of the valve without steam pressure present. In addition, the different coefficients of thermal expansion between the disk and nozzle material resulted in relative motion between the two components. The licensee concluded that, without steam pressure present, this motion took place under relatively high seat loads and resulted in gauling. Through testing, the licensee also determined that elevated temperatures during normal operation were necessary for the micro-bonding to occur. The results of the augmented test program indicated that bonding might occur within 90 days of reinstallation at normal operating temperature and pressure.

Inspection Followup

The licensee's immediate action was to assure that all main steam safety valves were left within the technical specification tolerance following testing and any required adjustments. The inspectors reviewed Action Requests A0410736, dated August 8, 1996, and A0410736, dated August 7, 1996, and verified that the valves were reset to be within the technical specification tolerance. The inspectors found that the licensee replaced the Unit 1 disks during the Unit 1 Refueling Outage 1R8 and had scheduled disk replacement for Unit 2 during Refueling Outage 2R8 (which began February 1998). To minimize micro-bonding between the disk and nozzle seat, the licensee replaced the 422 stainless steel disks with Inconel X-750 disks. The licensee stated that the Inconel material had a coefficient of thermal expansion closer to that of the seat material which minimized the relative motion between the disk and nozzle seats. The inspectors reviewed licensee Letter DCL-97-073, dated May 2, 1997, to the NRC, which addressed the augmented testing of the main steam safety valves. The licensee stated that, as a result of three main steam safety valves lifting low during a dual unit trip on August 10, 1996, they determined that use of the valve specific correlation factors derived from the AVK test equipment bias data resulted in main steam safety valve set points that were outside technical specification limits. The licensee found that the tests using the Trevitest test equipment provided result correlations that were closer to the results recorded by the plant computer than those provided by the AVK test equipment results.

The licensee discontinued the use of AVK test equipment and valve-specific correlation factors due to the findings from the August 1996 dual unit trip. The licensee further stated that the set points for both units were adjusted using the Trevitest test equipment. The inspectors reviewed Surveillance Test Procedure STP M-77B, “Augmented Test Program for Main Steam Safety Valves with Inconel X-750 Disks”, Revision 0, and noted that the test procedure required the valves to be tested with Trevitest equipment. The inspectors reviewed the main steam safety valve test data and noted that, since the Trevitest equipment was being used, none of the valves tested exceeded the technical specification set point tolerance.

The inspectors determined that the licensee's actions in response to this series of events were satisfactory.

This violation of Technical Specification 3.7.1.1 was previously cited in NRC Inspection Report 50-275;323/96-12.

E8.08 (Closed) Licensee Event Report 50-275/96-013: Main Steam Safety Valves Set Outside Technical Specification 3.7.1.1 Following Use of Inaccurate Mean Seat Areas Due to Personnel Error

Background

On April 11, 1996, for Unit 1, and August 7 and 8, 1996, for Unit 2, with each unit in Mode 1 at 100 percent power, Technical Specification 3.7.1.1 was not met when the main steam safety valves were set outside of the maximum tolerance of +/- 1 percent of the nominal lift pressure. The licensee stated that the main steam safety valves were set using AVK test equipment that used inaccurate mean seat areas. The licensee discovered this condition August 10, 1996, when both units tripped. Two Unit 1 and two Unit 2 valves lifted at a pressure lower than the set point during the trip. The licensee performed post-trip set point verifications with Trevitest equipment. The licensee stated that, after the Trevitest testing, all of the main steam safety valves were left within technical specification tolerances.

Inspection Followup

The licensee's corrective actions for using an incorrect mean seat area was to change the test equipment from the AVK to the Trevitest equipment and to use the Trevitest mean seat area. The licensee's corrective actions, discussed in Section E8.07 of this report, were sufficient to resolve this item.

This violation of Technical Specification 3.7.1.1 was previously cited as a noncited violation in NRC Inspection Report 50- 275;323/96-21.

E8.09 (Closed) Violation 50-275/9703-03: Failure to Take Adequate Corrective Actions Resulting in Water in the Auxiliary Feedwater Pump Turbine

Background

In August 1996, the licensee identified an abnormally high concentration of water in the oil within the governor of the turbine-driven Auxiliary Feedwater (AFVV) Pump 1-1, but failed to take adequate corrective action to preclude repetition. An action request was not written and additional review of the root cause and followup investigation of the potential impact on pump operability was not initiated. This led to a second discovery of water in the governor oil system in April 1997.

Inspection Followup

In August 1996, the system engineer chose not to write an action request for the discovery of water in the oil because it was determined that the water did not affect the operability of the governor. Although the 500 ppm of water found in the oil sample was higher than expected, the system engineer concluded that there was no operability impact because the water content was only 25 percent of the general rule-of-thumb maximum limit for proper lubrication of 2,000 ppm. Later examination of the control guide for the turbine showed that the actual water content upper limit was 5,000 ppm for proper lubrication. Although at the time it was thought that the sample could be flawed or contaminated, there was insufficient oil left in the system to take a second sample. The system engineer decided to change the governor oil to establish a new baseline. The new oil was sampled to assure that it was free of water. In April 1997, when the next sample indicated water intrusion similar to that indicated in the previous sample, an action request was written. The licensee agreed that an action request should have been written after the first sample disclosed a higher than expected moisture content and that the sample frequency should have been increased.

Licensee corrective actions included the following:

1. The lube oil heat exchanger for turbine-driven AFW Pump 1-1 was replaced during Unit 1 Refueling Outage 1 R8.

2. Applicable procedures were revised to include threshold limits for lube oil sample results in order to determine when action requests are written.

3. An oil sample taken 3 months after Refueling Outage 1R8 ensured that the water intrusion problem was corrected by replacement of the lube oil heat exchanger.

4. Maintenance Procedure MA1.DC52, Maintenance Services Predictive Maintenance Program," Revision 1A, was revised with an on-the-spot-change on August 19, 1997. The on-the-spot-change revised paragraph 4.3 to require initiation of an action request if abnormal data was received, frequency of data collection needed to be changed, or if greater than 2000 ppm water was measured in the oil.

The inspectors reviewed the licensee's corrective actions and concluded that the corrective actions appeared sufficient to preclude recurrence of the violation. The inspectors reviewed the revised Maintenance Procedure MA1.DC52, and verified that Revision 1A required an action request be generated if it was determined there was over 2000 ppm water in the oil. Although the 2000 ppm water limit would not require the issuance of an action request if the same event were to occur again, i.e., 500 ppm of water, the inspectors were assured by the licensee that, in this event, a second confirmatory sample (and, if necessary, additional, more frequent, samples) would be taken to assure that the lubrication limit of 5000 ppm would not be exceeded.

E8.10 (Closed) Violation 50-275:323/9717-01: Failure to Correct Smoke Detector Sensitivity

Background

The NRC identified that the licensee, between 1988 and 1993, initiated approximately 21 action requests documenting problems associated with inaccessibility and sensitivity testing of the various smoke detectors. The corrective actions associated with these action requests failed to promptly correct a nonconformance regarding the failure to test smoke detector sensitivity. Specifically, three detectors in Unit 1 and one detector in Unit 2 had not been tested within the established 5-year frequency.

Inspection Followup

A small number of smoke detectors were not sensitivity tested due to inaccessibility. The licensee stated that smoke detector sensitivity testing was a licensing commitment, incorporated into the Final Safety Analysis Report by reference to the National Fire Protection Association code. This code stipulated following the manufacturer's instructions for maintenance activities, which included sensitivity testing of the smoke detectors.

The licensee's surveillance test procedures established operability for the fire and smoke detectors through the performance of functional tests. However, licensee personnel did not recognize that sensitivity testing, while implemented in the test procedures, was a licensing commitment. In addition, licensee personnel believed, incorrectly, that detectors became more sensitive with time due to dirt accumulation and that detectors would fail safe. Engineering personnel inappropriately used this justification in lieu of providing a method for performing sensitivity testing. As a result, corrective actions to resolve inaccessibility for sensitivity testing were not timely. This issue was identified in May 1997 during a licensee fire protection audit. The licensee agreed that more timely corrective actions should have been implemented.

The corrective actions taken to prevent recurrence and future actions were as follows:

1. The licensee inspected the detectors identified in the 21 action requests and concluded that a total of eight detectors were inaccessible for sensitivity testing. These eight detectors were to be modified to allow future sensitivity testing by the end of Unit 2 Refueling Outage 2R8 for both Units 1 and 2.

2. The detectors originally were classified as inaccessible, but were later determined to be accessible, were sensitivity tested by the end of Refueling Outage 2R8 for both Units 1 and 2. At the time of this report, all testing was completed on Unit 2 and only two detectors in Unit 1, both located over the main steam lines, remained to be tested. Refueling Outage 2R8 began in February 1998.

3. Some detectors could only be tested during a unit outage due to personnel safety concerns or physical locations near equipment which has the potential to trip the plant if tested during plant operations. These detectors were to be sensitivity tested by the end of the Unit 1 Refueling Outage 1R9 for Unit 1 and by the end of Refueling Outage 2R8 for Unit 2. The Refueling Outage 1 R9 was scheduled to begin in February 1999.

The inspectors determined that the licensee's completed and planned actions in response to this issue were satisfactory for resolution of this issue.

E8.11 (Closed) Violation 50-275:-323/9717-02: Failure to Control Transient Combustible Materials

Background

The NRC identified that an area in the intake structure containing safety-related equipment included the following materials: (1) five aerosol cans and a one gallon plastic container of flammable liquids, not in use and not stored in a flammable liquid cabinet; (2) several untreated wooden pallets; (3) combustible packaging material consisting of several cardboard boxes used for storing materials; and (4) an unattended chair and ventilation ductwork, composed of combustible materials in red-painted no-combustible storage areas.

Inspection Followup

The licensee believed that these fire protection housekeeping issues were not representative of the other areas of the plant. While the exact cause for each of the conditions listed in the violation could not be determined, it appeared that, in general, the intake personnel did not have a clear understanding of the requirements of Procedure IDAP OM8.ID4, Control of Flammable and Combustible Materials," Revision 5.

The corrective actions taken to prevent recurrence were as follows:

1. The licensee conducted walkdowns of the intake area by an intake team to correct any conditions that did not conform to the requirements of Procedure IDAP OM8.ID4. Afterward, nuclear quality services and fire protection personnel verified compliance with Procedure OM8.ID4. These walkdowns were completed on December 18, 1997.

2. The licensee conducted a meeting during the week of October 1, 1997, of all intake personnel regarding expectations for the control of combustibles in accordance with Procedure OM8.ID4.

3. The licensee assigned the maintenance foreman responsibility and accountability for control of combustibles and flammables in the intake structure. The licensee instructed the organizations performing support functions at the intake structure concerning their responsibility and part in assuring procedure compliance. This action was completed on October 1, 1997.

4. Procedure IDAP OM8.ID4, Section 4.8, was revised to clarify that no unanalyzed transient combustibles were permitted in the red-painted, no-combustible storage areas from the floor to the ceiling. This revision was completed on February 15, 1998.

5. A flammable liquid storage locker was installed in the intake structure to facilitate compliance with Procedure OM8.ID4. This action was completed on February 5, 1998.

6. A maintenance self assessment was to be performed within 6 months to verify that the corrective actions have been effective. This self assessment was planned to be completed and documented by June 26, 1998.

The inspectors reviewed the completed and planned corrective actions, and concluded that they appeared sufficient to prevent recurrence of the violation. The inspectors walked down the intake structure with fire protection personnel, and identified no transient combustibles in the red-painted, no-combustible storage areas. The inspectors examined the flammable liquid storage locker detailed in Corrective Action 5 above. The inspectors determined that the intake structure was in compliance with Procedure IDAP OM8.ID4 at the time of this inspection.

E8.12 (Closed) Inspection Followup Item 50-275/97202-01: Review of Ultimate Heat Sink Calculation

Background

During normal plant operation, auxiliary saltwater (ASW) was provided to one of the two component cooling water (CCW) heat exchangers for each unit. Technical Specification 3.7.12 required that whenever the ultimate heat sink (UHS) saltwater temperature exceeded 64°F, the second CCW heat exchanger was to be placed in service within 8 hours or the plant was to be placed in at least hot standby within the next 6 hours and in at least hot shutdown within the following 6 hours.

Considering the "El Nino" effects on Pacific Ocean temperatures, the NRC questioned what maximum UHS temperature (above 64°F) would allow safe operation with the plant in the two-CCW heat exchanger lineup. The licensee had no analysis addressing this plant operating condition.

Inspection Followup

In response to this concern, the licensee issued three calculations, which together established the limits of operation with elevated UHS temperatures as follows:

1. Calculation M-1027, "Determine the Maximum Allowable ASW Temperature When Two CCW HXs Are Aligned," Revision 0, December 30, 1997, assessed the limits on plant operation in Modes 1 through 3. It determined that UHS temperatures as high as 75°F were acceptable with two CCW heat exchangers in service.

2. Calculation WCAP-14282, "Evaluation of Peak CCW Temperature Scenarios for Diablo Canyon Units 1 and 2," Revision 1, December 1997, assessed the CCW temperature responses to various accident and failure scenarios to determine the maximum CCW temperature. Case 9 was a sensitivity study case for a loss-of coolant accident (LOCA) with two ASW pumps supplying two CCW heat exchangers that had not been previously addressed in other calculations.

3. Calculation M-1020, "Evaluate the CCW System for Mode 4 Operation with Elevated UHS Temperatures," Revision 0, November 21, 1997, determined the maximum UHS temperature for which a single CCW heat exchanger could support Mode 4 operation. This was to determine the maximum UHS temperature for which a safe shutdown could be accomplished if a second CCW heat exchanger could not be placed in service within 8 hours as required by the technical specifications. This temperature was 70°F, and this was established as the UHS upper temperature limit.

The licensee committed to incorporate this limit into the design basis with Design Change Package (DCP M-49386 by June 1, 1998, and into the ITS as part of the response to an NRC request for additional information associated with ITS Section 3.7.

The inspectors reviewed the above calculations and the licensee's responses to this item. No discrepancies were identified in these documents. However, the team did question the increased CCW temperature limit, from 120°F to 140°F, that was incorporated in Calculation WCAP-14282 with respect to the ability of the equipment cooled by CCW to remain functional at this elevated temperature. Sample re-qualification documents for the residual heat removal pump mechanical seal, the safety injection pump mechanical seal and lube oil system, and the centrifugal charging pump mechanical seal and lube oil system were reviewed by the inspectors and found to acceptably demonstrate the capability of this equipment to properly function.

E8.13 (Closed) Inspection Followup Item 50-275/97202-02: Review of Revision to WCAP-14282 and Incorporation into Design Basis Documentation

Background

The NRC observed that in the original revision of Calculation WCAP-14282, "Evaluation of Peak CCW Temperature Scenarios for Diablo Canyon Units 1 and 2," high fouling factors had been used for the various heat exchangers, consistent with conservatively demonstrating the capacity to meet the design basis heat transfer requirements for the various system heat loads. However, this assumption was not conservative with respect to the CCW temperature. For very low fouling factors, which was consistent with actual plant experience, the heat transfer rate into CCW could be much higher, resulting in higher than calculated CCW temperatures. At the time of the inspection, this WCAP was being revised to address this concern, and the licensee had issued Action Request A0439116 to track the changes necessary to incorporate the revised WCAP results into design basis documentation as presented in design criteria memoranda (DCM) documents and the Final Safety Analysis Report.

This NRC also identified that there were no procedural controls to limit CCW heat exchanger tube plugging to the 2 percent allowed by the manufacturer. Action Request A0443543 was initiated to generate procedural controls to limit tube plugging without reanalysis.

Inspection Followup

The inspectors reviewed the revised WCAP-14282 (Revision 1) and identified no discrepancies. The affected DCMs were in various stages of revision; Design Change Package (DCP) M-49386, to change the Final Safety Analysis Report, was targeted for a June 1, 1998, completion, and the other affected calculations had been identified, with several having been changed but not yet checked. However, none of the documents affected by this calculation had gone through the complete revision process at the time of this inspection.

The inspectors concluded that the revised WCAP and the related calculations discussed in the preceding item (Section E8.12) adequately addressed the previously-identified design concerns. Although revisions to the other affected design and licensing documents were incomplete, the inspectors verified that these actions were being tracked satisfactorily.

E8.14 (Open) Unresolved Item 50-275/97202-03: Determine If Current Approach to Sinale Failure Design Represents a USQ

Background

The original design intent for the ASW and CCW systems was that they be separated into two redundant trains for long-term post-LOCA cooling as described in Final Safety Analysis Report Section 9.2.7.2, thus, assuring their ability to withstand a single passive failure. This was reflected in Emergency Operating Procedure E-1.4, "Transfer to Hot Leg Injection," Revision 12, which required train separation at approximately 10 1/2 hours after a LOCA. However, the licensee discovered that when the trains were separated, the accident heat removal capabilities of these systems, in conjunction with the residual heat removal system, were vulnerable to single active failure in two scenarios. First, for the postulated loss-of-electrical Bus F, CCW cooling flow in Loop B and ASW cooling flow in loop A would be lost, and second, for the postulated loss-of-electrical Bus G, ASW cooling flow in Loop B and residual heat removal flow in Loop A would be lost.

With this discovery, on March 3, 1997, the licensee initiated Licensee Event Report (LER) 1-97-001, "The Component Cooling Water System Has Operated With Procedural Guidance That Permitted Operation in a Condition Outside the Design Basis of the Plant." Corrective action was to change Emergency Operating Procedure E-1.4 to no longer require train separation, but to make separation optional, and to transfer the train separation decision to the Technical Support Center (TSC), where the decision would be made after an evaluation of plant conditions. The NRC determined that since this mode of operation was not consistent with the original design or licensing basis, it potentially constituted an unreviewed safety question (USQ).

Inspection Followup

The inspectors' review focused in two areas: (1) the licensee's actions following identification of this vulnerability and (2) determination of an unreviewed safety question. The following observations were made:

Licensee's Responses to Single Failure Vulnerability

The licensee's responses to the discovery of these single failure vulnerabilities included the following:

1. Revision of the emergency operating procedure, as described above, to make separation of the ASW/CCW trains optional and to transfer this decision to the TSC.

2. Revision of TSC Procedure PEP EN-1, "Plant Accident Mitigation Diagnostic Aids and Guidelines," Revision 6, to incorporate guidance on train separation.

   - Revision of the UFSAR to reflect these procedural changes.

   - Upgrade of the operators for ASW Train Cross-Connect Valves FCV-495 and FCV 496 to allow remote manual operation from the control room.

   - Issuance of Non-Conformance Report (NCR) N002010, “Separation of ASW and CCW Systems in Post-LOCA Operation," Revision 0.

The team reviewed these responses and found that they satisfactorily addressed the technical concerns with the single failure vulnerabilities identified. With these changes, during the injection phase of an accident, when only an active failure was required to be considered, the ASW/CCW systems would be operated in the cross-connected mode. An active failure in this phase could reduce flows, but not to the extent where the systems could not perform their safety functions. In the long-term, when both an active and passive failure were required to be considered, the decision to separate the systems would be deferred to the TSC, where the plant status would be evaluated. If the decision were made to leave the systems split, they would still be protected from active failure. For passive failure as defined in the UFSAR (a 50 gpm leak for 30 minutes), the licensee was able to show that, for the CCW system, operator action could be taken in that time to detect and isolate the leak, and the water loss from the system would not be sufficient to incapacitate either train; for the ASW system, a loss of this volume could be tolerated indefinitely without affecting the system's ability to perform its safety function. Additionally, the upgrade of cross-connect valves FCV-495 and FCV-496 assured the ability to quickly split the trains remotely from the control room if so desired.

The USQ Question

The licensee's position regarding whether this concern constituted a USQ remained unchanged from the time of the previous inspection and was essentially contained within the 10 CFR 50.59 safety evaluations that had been produced as a part of the Final Safety Analysis Report and emergency operating procedure change processes. The primary elements of these safety evaluations, as contained in the licensee's response letter to the NRC, Letter DCL-98-007, dated January 12, 1998, were that:

1. The changes did not affect the design of any system or the ability of the systems to perform their safety functions.

2. The changes did not affect assumptions made in the Final Safety Analysis Report accident analyses, nor the results of these analyses.

3. Indications of a single failure and system conditions were available, procedures were in place to perform the necessary/appropriate actions, and responses could be made in an acceptable time frame.

The inspectors agreed, generally, with the licensee's position with one exception. The emergency operating procedure change did result in a change in the system response to a passive failure during the long-term recirculation phase. Prior to the change, with the trains separated, no operator action was necessary to prevent a passive failure from debilitating both trains. After the change, operator action was a necessary element in the response to a passive failure. This change in the accident scenario potentially constituted a USQ. This item was left open pending additional review by the NRC.

During this review, the inspectors observed that the CCW system was normally pressurized with nitrogen supplied to a common surge tank for both divisions. This feature was described in NRC Generic Letter 96-06, "Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions," that involved the potential for water hammer in containment fan cooler units during accidents due to voiding following loss of power. This design incorporated a single pressure control valve intended to vent nitrogen pressure from the tank at the upper end of the normal operating pressure band. Such venting could be expected for events that would add significant new heat loads to the system, such as a LOCA, thereby causing an increase in the system's bulk temperature and the resultant expansion of the water in the system and raising of the system pressure. The team noted that for such an event, if the pressure control valve were to fail to close, all nitrogen pressure could be vented, thereby defeating this waterhamer protection feature. If such an event were to be accompanied by a loss-of-offsite-power (LOOP), the potential would exist for voiding and subsequent water hammer in the containment fan coolers when the CCW pumps were restarted after the emergency busses were re-energized by the emergency diesel generators. It appeared that the potential would be greater if the LOOP occurred after the LOCA, because more time would have been available for CCW system heatup and releasing of the nitrogen pressure from the system.

The licensee responded that this was not a credible concern if the LOCA and the LOOP were considered to occur simultaneously, since there would be insufficient time for system heatup and pressure relief before the CCW pumps would be restarted; therefore, there would be no waterhammer. Furthermore, the licensee considered this scenario to be outside the plant's licensing basis, i.e., the licensing basis only required consideration of LOOP coincident with LOCA.

Based on this review, the inspectors considered that a potential existed that made the CCW system vulnerable to a failure of the CCW surge tank back pressure regulator valve to close coincident with a non-simultaneous LOCA and LOOP. The inspectors concluded that this scenario was beyond the licensing basis of the plant and of very low probability.

Conclusion

The deletion of procedural steps to separate trains of the auxiliary saltwater and component cooling water systems, when transferring to hot leg injection during a loss of coolant accident recovery appeared to constitute an unreviewed safety question. This unresolved item was left open pending additional review by the NRC.

E8.15 (Open) Inspection Followup Item 50-275/97202-04: Modification to ASW Pump Testing Method

Background

The NRC discovered that the method used by the licensee for performing ASME Section XI testing of the ASW pumps was with the system cross-connected, with each pump supplying the opposite train's CCW heat exchanger. This configuration was used to provide the maximum system resistance and hence the most conservative lineup. For this test, the CCW heat exchanger outlet valve, a sealed, throttled valve, was unsealed and adjusted to regulate the flow to the test reference value. This adjustment was different for each test, depending on the ocean tide level at the time of the test. If this was a pump post-maintenance test, the pump's division would be considered inoperable until the test was successfully completed. Likewise, while the opposite train's CCW heat exchanger outlet valve was unsealed, that division could also officially be considered inoperable, making both divisions technically inoperable at the same time. However, with this configuration, both trains were capable of supplying sufficient flow to satisfy design basis flow requirements. Therefore, no safety concern existed.

Inspection Followup

In response to this finding, the licensee submitted a relief request letter to the NRC (DCL-97-210, dated December 12, 1997, "Inservice Testing Relief Request P-RR5 - Auxiliary Saltwater Pump (ASWP) Performance Using Evaluation of Pump Curves," to allow ASW pump testing using an evaluation of pump performance compared to pump curves in lieu of single reference points, as allowed by Operation and Maintenance Part 6 (OM-6), "Inservice Testing of Pumps in Light-Water Reactor Power Plants," paragraph 5.2(b). This would eliminate the need to adjust the CCW heat exchanger outlet valve and the resultant declaring of the affected ASW/CCW train inoperable.

The inspectors reviewed the relief request letter and the NRC's recommendations for use of the pump curves in lieu of reference points contained in NUREG-1482, 4/95, "Guidelines for Inservice Testing at Nuclear Power Plants," Section 5.2, "Use of Variable Reference Values for Flow Rate and Differential Pressure During Pump Testing." The NUREG described the general requirements for allowing such relief as well as seven specific requirements for preparing the pump curves to be used. The licensee had committed to all of these general and specific requirements in the relief request and had provided clear arguments that demonstrated the impracticality of the current method of testing and the need for this relief.

The inspectors concluded that the licensee's actions regarding this item were appropriate and timely, and that they committed to fulfill all of the regulatory and ASME Code guidance for cases such as this, including assuring that the pump performance would meet not only the Code required acceptance criteria, but also that they would also meet the minimum accident analyses performance requirements, as addressed in NRC Information Notice 97-90, "Use of Non-conservative Acceptance Criteria in Safety-Related Pump surveillance Tests." Pending this approval and implementation of the proposed changes, this item remained open.

E8 16 (Closed) Unresolved Item 50-275:-323/97202-05: Discrepancies in Design Documentation

Background

The NRC identified four examples where the licensee's documentation of design bases information was inconsistent with actual plant design.

In the first example, the NRC found that the piping temperature classification for the auxiliary saltwater system (ASW) in design criteria memorandum (DCM) S-17, “Auxiliary Saltwater System," Revision 4, did not reflect the correct values specified in Calculation M-784, "Auxiliary Saltwater System," Revision 1, which determined the maximum system pressures and temperatures for various modes of operation. The NRC reviewed Calculation M-784 and determined that the pressure and temperature classification in the calculation was acceptable and that, therefore, no safety concern existed.

In the second example, the NRC identified that Technical Specification Basis B3/4.3-1 for the ASW system did not describe the start of the ASW pumps in response to the engineered safety features actuation signal. The NRC noted that the Final Safety Analysis Report stated that the ASW pumps were started from the engineered safety features actuation signal. Since this was consistent with the actual design, the issue did not constitute a safety concern.

In the third example, the NRC identified that Technical Specification Bases B3/4.5.5 did not describe verification of the refueling water storage tank temperature as a necessary parameter to establish operability of this tank. The NRC noted that Technical Specification Section 3/4.3.2 for the refueling water storage tank described verifying the storage tank temperature to establish operability during low outside ambient temperature conditions. The technical specification bases only mentioned the refueling water storage tank volume and boron concentration as a requirement for operability.

In the fourth example, the NRC identified that Design Criteria Memorandum S-12, Containment Spray System," Revision 6, did not correctly identify that a coincident high-high containment pressure signal was necessary to start the containment spray pumps when a safety injection signal was received. The team found that the design criteria memorandum only described the high-high containment pressure signal as being necessary for automatic actuation of the containment spray system. The NRC found that the Final Safety Analysis Report stated that receipt of the high-high containment pressure signal was required in combination with the safety injection signal to automatically initiate containment spray.

The NRC also identified two examples (identified as the fifth and sixth examples below) where the licensee failed to update the Final Safety Analysis Report to reflect plant conditions. In both cases, these conditions existed for greater than six months prior to the previous update of the Final Safety Analysis Report.

In the fifth example, the NRC identified that Section 9.2.2.1 of the Final Safety Analysis Report stated that "based on design basis accident heat load, one of the following four conditions must be satisfied as a minimum to maintain the auxiliary saltwater system design basis." The NRC identified that "auxiliary saltwater system" should have read "component cooling water system."

In the sixth example, the NRC identified that Section 6.2.3.5.3 of the Final Safety Analysis Report stated that two alarms were provided to announce that the spray additive tank solution had been exhausted. Based on control room annunciator layout Drawing 500808 and the as-installed condition, only one alarm existed. Also, this alarm announced that the technical specification level of 60 percent in the spray additive tank had been reached, instead of being exhausted as stated in the Final Safety Analysis Report.

Inspection Followup

For the first example, the inspectors reviewed Action Request A0438253, dated August 8, 1997, and determined that the licensee initiated this document to revise DCM S-17B to reflect the correct temperature classification described in Calculation M-784. In addition, the inspectors reviewed Action Request A0449058, dated December 11, 1997, and found that this document was initiated to correct the temperature and pressure classification in DCM S-17B for the auxiliary saltwater system. The licensee stated that the completion date for this task (Action Request A0449058) was June 1, 1998. In licensee Letter DCL-98-007 dated January 12, 1998, the licensee stated that this condition was considered to be an isolated problem with no generic implications since the correct information regarding pressure and temperature classification was provided in DCM M-46, "Piping Pressures, Temperatures, and Operating Modes-Unit 1." After the inspection the licensee submitted supplemental information concerning this item.

The licensee stated that the design criteria memoranda were developed to be used by personnel that understood their use and limitations. In addition, the licensee stated that their personnel understood that they needed to use the most specific information available, which might be in the design criteria memorandumor in some other design basis document. In the case of pressure and temperature information, the licensee personnel were trained to use two generic design criteria memoranda which provided piping pressure and temperature. The inspectors agreed with the licensee's position.

For the second example, the licensee determined that the addition of the auxiliary saltwater system pumps to the bases was not required. The licensee stated that when the technical specification bases listed the safety injection functions, it referred to them as examples of safety injection equipment that would actuate in response to a loss of coolant accident or main steam line break. The licensee stated that since the list was a list of examples, it was not required to be all inclusive. The inspectors reviewed Final Safety Analysis Report Section 7.1.2.1.2.2 which discussed the requirements imposed on the safety injection signal by the design basis. The inspectors found that the ASW system pumps were included in the discussion in the Final Safety Analysis Report and noted that the technical specification bases and the Final Safety Analysis Report were identical with the exception of the exclusion of the ASW system pumps. The inspectors reviewed NUREG-1431, “Standard Technical Specifications Westinghouse Plants," and determined that the bases for Technical Specification 3.3.2 included an example list of equipment started on a safety injection signal. The inspectors noted that the list in NUREG-1431 did not contain all of the equipment started by a safety injection signal. Based on this information, the inspectors concluded that the licensee's technical specification bases was acceptable.

Concerning the third example, the inspectors reviewed Surveillance Test Procedure (STP) R-20, “Boric Acid Inventory," Revision 18, for the refueling water storage tank, and found that the tank temperature measurement was included in the procedure. The inspectors reviewed License Amendment Request 94-06, dated August 17, 1994, which the licensee initiated to delete the minimum refueling water storage tank solution temperature and increase the allowed outage time of the refueling water storage tank for adjustment of boron concentration from 1 hour to 8 hours. At this time, the licensee deleted reference to the tank temperature measurement from the technical specification bases. However, the NRC did not approve the deletion of the refueling water storage tank temperature and in the NRC response letter to the amendment request, dated

April 14, 1995, the NRC required the licensee to revise the bases submitted with the amendment to retain reference to the temperature measurement. The licensee did not revise the bases as stipulated in the NRC response letter, such that the refueling water storage tank temperature remained in the technical specification surveillance section, but not in the bases section. In response to this issue, the licensee stated that information regarding the refueling water storage tank temperature was added to the technical specification bases of the improved technical specifications, which was submitted to the NRC on June 2, 1997. The inspectors determined that this action by the licensee was sufficient to resolve this concern.

Regarding the fourth example, the inspectors reviewed Action Request A0441273, dated August 7, 1997, which was initiated by the licensee to revise the DCM S-12 to correctly identify when containment spray would be initiated. The inspectors determined that the licensee had identified this discrepancy in advance of the NRC identification. The inspectors reviewed DCM S-12, and determined that the licensee appropriately revised this document to clarify that the containment spray system was initiated by a safety injection signal coincident with a high-high containment pressure signal. The inspectors determined that the licensee took adequate corrective actions to clarify the discrepancy. The licensee's response letter stated that both the DCM and the Final Safety Analysis Report were revised to clearly identify the requirement of coincidental signals for the automatic actuation of the containment spray system. The inspectors reviewed Action Request A0441540, dated August 12, 1997, which was initiated to correct the Final Safety Analysis Report descriptions of containment spray initiation. The inspectors reviewed a Final Safety Analysis Report update change request dated August 25, 1997, which revised Sections 6.2.2.2.2.1, and 6.2.3.2.1 and found that the licensee added that containment spray required both a high-high containment pressure signal and a safety injection signal in order to actuate. The inspectors noted that the licensee identified this discrepancy in the Final Safety Analysis Report while they were performing a design bases review of the Final Safety Analysis Report. The change to the Final Safety Analysis Report was needed only for clarification purposes; it did not represent an actual error in this document.

Concerning the fifth example, the inspectors reviewed Action Request A0441163, dated August 6, 1997, which the licensee initiated to correct Section 9.2.2.1 of the Final Safety Analysis Report. The licensee determined that the change was an editorial correction since it was a clarification only and was not considered to be a quality problem. This example of failure to maintain the accuracy of the Final Safety Analysis Report will be added to other examples of Final Safety Analysis Report discrepancies currently under NRC review as part of open Unresolved Item 50-275;-323/9606-06.

In the sixth example, the licensee stated in their response letter that they would revise Design Criteria Memorandum S-12 and the Final Safety Analysis Report to clarify the description of the spray additive tank alarms. The inspectors reviewed Action Request A0442941, dated September 3, 1997, which was initiated by the licensee to revise Section 6.2.3.5.3 of the Final Safety Analysis Report to correct the statement that there were two alarms to announce that the spray additive tank was exhausted. In this action request, the licensee committed to a completion date February 27, 1998. The inspectors reviewed the Final Safety Analysis Report update change request, dated December 3, 1997, and found that Section 6.2.3.5.3 was revised to state that one alarm was provided to announce when the solution in the tank dropped below a level approaching the Technical Specification minimum requirements. In addition, the inspectors reviewed Action Request A0449235, dated December 15, 1997, which the licensee initiated to correct the DCM S-12, "Containment Spray System." The DCM contained the same error as the Final Safety Analysis Report regarding the number of alarms. The inspectors reviewed DCM S-12, Revision 7 and found that it was revised on February 2, 1998, to include the corrections. This example of failure to maintain the accuracy of the Final Safety Analysis Report will be added to other examples of Final Safety Analysis Report discrepancies currently under NRC review as part of open Unresolved Item 50-275;-323/9606-06.

E8.17 (Closed) Unresolved Item 50-275/97202-06: Availability of an Alternate Flowpath for the ASW System Suction

Background

The auxiliary saltwater (ASW) system was designed to draw water from the Pacific Ocean (the plant's ultimate heat sink (UHS)) through a common intake screen. This was described in Final Safety Analysis Report Section 9.2.7.2.3 as follows, "Each unit's pair of ASW pumps share a common traveling screen to remove floating debris from the incoming seawater. If the common screen for a unit becomes clogged with debris, seawater may be valved to the ASW pump bays from the unit's circulating water pump bays." This alternate flowpath from the circulating water pump bays was a 24-inch "demusseling" line in each unit containing air-operated, fail as-is, butterfly valves. The NRC observed that the screens were not seismically qualified; therefore, if a screen failed as a result of a seismic event, flow could be restricted to the ASW pumps. They also observed that, although the valves in the alternate flowpath were being routinely exercised, contrary to the recommendations of Generic Letter (GL) 89-13, “Service Water System Problems Affecting Safety-Related Equipment, "this alternate flow path was not being tested or maintained to demonstrate its availability.

Inspection Followup

In their response letter to the NRC, DCL-98-007, dated January 12, 1998, the licensee stated that the "demusseling" lines were not a required redundant ASW flowpath, and therefore, they were not considered as required to be maintained or tested in accordance with their Generic Letter 98-13 Program. The licensee based their statement on the following:

1. In a review of the design basis of the demusseling flow paths, the licensee determined that the air-operated demusseling valves were Design Class II, with no provisions in the design to ensure that the flow path could be placed in service under all plant conditions, including a seismic event. Therefore, since they were not fully qualified, this was not intended as a licensing basis alternate flow path.

2. Operators could take actions in case of loss of ASW pump suction to start the nonoperating pump or to utilize the opposite unit's standby pump through the unit cross-tie valve. Specifically, Final Safety Analysis Report Section 9.2.7.3, under the subtopic “Safety Evaluation," stated, “The unit crosstie provides operating flexibility in that it is possible to have the Unit 2 standby pump provide water to Unit 1 in the event the Unit 1 standby pump is inoperable and vice versa." The licensee pointed out that while the above reference is in the “Safety evaluation" section of the report, the reference to the circulating water pump bays in Section 9.2.7.2.3 is in a “system description" section of the report. This, according to the licensee, signified that the actual alternate flowpath was from unit crossties. Further, the licensee indicated that since the circulating water bays did not contain any Design Class 1 features, it was not intended as a redundant ASW system flowpath.

3. The demusseling line was not considered a "cooling loop" as the term was used in Enclosure 1 of the Generic Letter 89-13, and as such was not required to be tested or maintained.

The licensee further stated that it recognized the value of ensuring viability of the alternate flow path as demonstrated by the current performance of the periodic demusseling valve stroke tests. In addition, the licensee committed in letter DCL 98-007 to the NRC, dated January 20, 1998, to inspect one of Unit 2's demusseling lines in Refueling Outage 2R8, to be completed by April 1998, and based on the results of this inspection, to further evaluate the need for periodic maintenance and testing by June 20, 1998. Following the onsite portion of this inspection, the licensee completed this inspection and found no fouling in this line. The licensee further stated that, since the water contained in this line was isolated from the external environment, no biofouling was expected to occur under any conditions.

The inspectors determined that the licensee's position that the circulating water bays were not intended as the design basis alternate suction path for ASW was acceptable. However, several points of concern with the existing design of this system were identified, as discussed below.

The licensee made the statement that operator actions could be taken in case of loss of ASW pump suction such as starting the second pump or opening the cross-tie valve to the opposite unit. However, it was evident from this statement that the full impact of a screen failure due to plugging or a seismic failure was not understood by the licensee. The most significant impact would likely be the immediate release of the material plugging the screen into the flow path of both ASW divisions in that unit, causing an almost immediate plugging of the on-line CCW heat exchanger(s), causing a heat transfer function failure, even if no damage was caused to the pumps. Starting a second pump, if it was not already running, would only serve to plug the second heat exchanger if the screen had already collapsed or increase the differential pressure across the screen if it had not, further increasing the potential for collapse. Opening the cross-tie valve to the opposite unit, as suggested by the licensee, would only serve to exacerbate the plugging likely to be occurring on that screen (the two units' ASW screens are only a few feet apart). The only operator action that would likely reduce the potential for screen collapse due to plugging would be opening the alternate flow path from the circulating water bay. This would increase the screen flow area by a factor of seven, thereby potentially reducing the loading rate and the differential pressure by a factor of up to 49 (loading rate and differential pressure are functions of the flow velocity squared).

The ASW primary flow path was through a nonseismically qualified, nonsafety-related, nonClass 1E powered, traveling screen served by a similarly nonqualified screen wash system. Therefore, this segment of the ASW system did not meet the GDC requirements applicable to all other safety-related systems, including the balance of the ASW system. Though not an acceptable design by today's standards, this was typical of emergency service water systems licensed in many other plants of the same vintage. However, the single common intake screen design in this plant was not typical; most other plants had separate intake screens for each train, which were verified clear as a result of their normal operation. The single screen design of this plant made it more vulnerable to screen failure than was typical and increased the probable consequences of such a failure, further indicating the special importance of maintaining and testing the alternate flow path in this plant. Additionally, the ultimate heat sink at Diablo Canyon is the Pacific Ocean, which cannot be maintained clear of debris to the same extent that a cooling pond or other similar holding area can at many nuclear plants. Therefore, the probability of clogging both the primary and alternate intake flowpath screens was greater.

The inspectors noted that service water intake screen failures due to high differential pressure have been experienced at several plants. Additionally, plugging and screen failure had been experienced at this plant with the circulating water screens due to kelp buildup, although severe ASW screen plugging had not been experienced due to the relatively low ASW flow velocities. However, this observation for normal operating conditions was not a valid basis for judging accident conditions, which could be significantly more severe as follows:

1. The circulating water screen failures were experienced in spite of the screens and screen wash system being fully operational, providing an indication of the severity of the kelp presence at times. Under accident conditions, the ASW screens and screen wash system may not be operational due to loss of offsite power or their assumed failure, since they were non-safety-related, even if offsite power were available. Under these conditions, the buildup rate would be significantly higher.

2. The relatively low debris buildup rate and differential pressure on the ASW screens versus the circulating water screens postulated by the licensee was under nonaccident conditions when only one ASW pump was normally operating. For accident conditions, with two ASW pumps running, the flow rate would double, which could increase the debris buildup rate and differential pressure by a factor of four.

3. The licensee stated that operator actions taken would be based on the operators' observations of screen differential pressure, intake bay level, etc. However, for accident conditions, none of these indications would be available due to loss of instrument air to the bubbler tubes for these instruments, or could be providing false indication of low differential pressure.

4. The licensee provided the various measures the operators could take to rotate the screens if power were lost to the drive motors. However, without coincident power restoration to the screen wash pumps, this would tend to bring the debris over the top of the screens, risking plugging of the CCW heat exchangers. Additionally, the licensee did not recognize that after a certain level of debris buildup, the screens can no longer be rotated either by hand, by their normal motors, or by outside machinery without risk of damage due to the very high friction caused by the differential pressure.

The inspectors concluded that the design of the auxiliary saltwater system appeared to be vulnerable to common mode failure scenarios of more than negligible safety significance. The significance of these vulnerabilities may not have been fully appreciated during original design and licensing. This issue will be further reviewed by the NRC and was identified as an inspection followup item (50-275;-323/9805-01). Because the licensee had met the licensing basis of the plant with regard to the alternate ASW suction path, this unresolved item was closed.

E8.18 [Closed) Unresolved Item 50-275/97202-07: EDG Transient Analysis Computer Simulation Study

Background

Design Criterion Manual (DCM) S-21, "Diesel Engine System," Revision 6, stated that each diesel generator was designed such that at no time during a loading sequence will the frequency decrease to less than 95 percent of nominal frequency. This procedure also stated that the diesel generators were designed to ensure that frequency is restored within 2 percent of nominal (60 hz) in less time than 40 percent of each load sequence interval. Regulatory Guide 1.9, "Selection, Design, and Qualification of Diesel-Generator Units Used as Standard Onsite Electrical Power Systems at Nuclear Power Plants," Revision 1, revised this time criteria to 60 percent, but the DCM did not reflect this new allowance.

The NRC reviewed Calculation 215-DC, "EDG Loading Capability Study without KWS Relay," Revision 1, in which the diesel generator transient responses were analyzed. This analysis indicated that four of the licensee's six diesel generators could drop to 56.8 Hz during design basis loading, which was slightly under the 95 percent of nominal criteria (57 Hz). Also, one diesel generator was calculated to require 2.54 seconds at one point in the design basis load sequence to be restored to within 2 percent of nominal frequency, which was greater than the Regulatory Guide 1.9, 60 percent criteria, for the 4-second loading interval (2.4 seconds). Despite the analytical anomalies, the integrated test of engineered safeguards and diesel generators, conducted on the diesels to monitor their performance, did not show any frequency dips below 57 hz or recovery times greater than 2.4 seconds. The disparity between test and analysis appeared to be the result of a slower-than-actual modeling of the diesel generator governor response time.

The licensee initiated Action Request A0444243 to evaluate current system capabilities, to resolve discrepancies in their commitment to emergency diesel generator response transient loading, and to revise Calculation 215-DC and DCM S-21.

Inspection Followup

The licensee was in the process of revising DCM S-21 and Calculation 215-DC with a completion date of February 28, 1998. The revision to DCM S-21 will incorporate the revised guidance in Regulatory Guide 1.9, Revision 1, allowing a frequency recovery time of 60 instead of 40 percent of the load sequence interval. The revision to Calculation 215-DC will not include a revision to the computer model or make any attempt to reduce the apparent over conservatism in the governor response times in the calculation. Instead, the calculation will include a discussion that will base compliance with Regulatory Guide 1.9 on a combination of the computer simulation and the integrated test results. Using this approach, the licensee was confident that they could adequately demonstrate that the criteria of Regulatory Guide 1.9 were met.

The licensee intended to submit a letter to the NRC by May 30, 1998, documenting the basis for compliance with Regulatory Guide 1.9, Revision 1.

The inspectors reviewed diesel generator test data and observed that the frequency response of the diesel generators for design basis loading sequences was well within the guidelines of Regulatory Guide 1.9, Revision 1. Therefore a safety concern did not exist. The remaining questions involving conformance to the guidelines of Regulatory Guide 1.9 will be resolved as part of the NRC review of the May 30, 1998 letter submitted to the NRC.

E8.19 (Closed) Inspection Followup 50-275/97202-08: Control of Calculations

Background

In review of Calculation 195C-DC, "Evaluate Adequacy of the Existing Thermal Overload Setting for 460 V Continuous Duty Motors," Revision 4, the NRC identified a discrepancy in an exception note explaining why larger size thermal overload heaters had been selected. The note indicated that the lower size heaters were not selected because they did not meet design requirements. This statement was incorrect. The actual reason for selecting the larger size thermal overload heaters was to preclude spurious trips on motor starts when the associated pump or fan was rotating in the reverse direction. The licensee initiated Action Request AR A0443258 to correct the exception note in Calculation 195A-DC.

The NRC noted that several design change notices (DCNs) providing as-built thermal overload settings were not updated in Calculation 195A-DC. The licensee initiated Action Request A0444411 to incorporate this information into the calculation.

The NRC identified a concern related to Procedure CF3.1D4, "Design Calculations," Revision 2, in that calculations that are made obsolete by a change are not required to be archived or made historical. This placed dependence on engineers to remember the calculational history. The NRC had difficulty determining the most current calculations that supported the system design.

The NRC identified that there was no periodic updating of large calculations to incorporate changes to limited scope calculations that affected the larger calculations. Also, the NRC identified that the revision dates of referenced industry standards were inconsistent within lists provided in the Final Safety Analysis Report, technical specifications, DCMs, calculations, and procedures. The licensee initiated AR A0444408 to address these concerns.

Inspection Followup

The inspectors observed that the thermal overload heater sizing described in Calculation 195C-DC was correct from a functional point of view and that the only concern involved the inaccurate explanation for the larger-than-typical sizing of the heaters. This was being tracked for inclusion during the next revision of the calculation.

On January 28, 1998, the licensee issued Revision 3 to Calculation 195C-DC, in which the noted DCNs and others were incorporated into the calculation. At the time of the inspection, the inspectors observed that the licensee did not have a procedural restriction on the amount of time to incorporate changes to a calculation. The changes were listed on a tracking action request that accompanied the calculation. Therefore, information regarding the change was always available to a calculation user, although not in the optimal ease-of-use presentation. In response to the inspectors observations, the licensee agreed to modify procedures to require affected master calculations to be updated with changes no later than 120 days following each refueling outage. The inspectors considered this procedural change to adequately address the original issue.

The inspectors reviewed the system used to identify superseded or outdated calculations and to prevent their use in quality activities. During the previous inspection, the design calculation index did not provide this information. However, if access were made to a superseded calculation, the copy obtained would be physically stamped as being superseded. Therefore, the system in place, though cumbersome, would have prevented the improper use of superseded design information. As a matter of enhancement, the licensee decided to revise Procedure CF3.ID4 to require the design calculation index to be revised on a point-of-use basis to show the status of calculations, including when they are placed in a superseded status. A second enhancement to Procedure CF3.ID4 was to include the tracking action request for master calculation updates in the design calculation index "remarks" field so that the user is alerted to the existence of a recently approved calculation not yet updated in the master calculation. Previous to this enhancement, this information was still available to the user in the tracking action request that accompanied the master calculation. The inspectors considered that the placement of this information in the design calculation index made the system more user-friendly. The licensee planned to incorporate changes to Procedure CF3.ID4 by May 31, 1998.

The inspectors reviewed the licensee's response to the NRC's identification of five industry standards that were inconsistently referenced in various plant documents with respect to their revision dates. The licensee was addressing this issue generically as part of a comprehensive review of electrical standards referenced in the DCMs and the Final Safety Analysis Report. Within this review, the licensee determined that the standards listed in the electrical DCMs were consistent. Electrical standards referenced by nonelectrical DCMs were sometimes inconsistent, but some of these discrepancies were explainable because they focused on what was applicable for the particular system or component and therefore were not intended to be comprehensive or to supersede references noted in the electrical DCMs . The licensee recognized a need to resolve any apparent inconsistencies in the references in the nonelectrical DCMs, and, at the time of this inspection, was preparing to begin this effort. The licensee's stated that by ensuring that the electrical DCMs referenced the correct versions of IEEE Standards, there was a high degree of confidence that the basis for the application of any IEEE standard could be traced to its source. The types of discrepancies that existed generally involved various references to revisions from the 1970's, such as a 1974 revision versus a 1977 revision. The differences in the information presented within these revisions was expected to be negligible and to not cause a material concern with any previous design work. To date, in its review, the licensee had not identified any examples where an inaccurately referenced IEEE standard would have caused a quality concern, and, as a result, no action items had been written relative to this issue. The inspectors concluded that the licensee's corrective actions were appropriate.

The inspectors determined that the findings discussed above did not result in a safety-related concern involving the licensee's calculation program. That is, the findings did not suggest that previous design changes or evaluations had been adversely affected by or based on inaccurate information. The licensee's responses, resolutions, and proposed enhancements appeared to be a positive step in making improvements in the calculation control process.

E8.20 (Closed) Inspection Followup Item 50-275:-323/97202-09: Review of Licensee's Evaluation of Battery Charger Settings

Background

The vital battery chargers were sized by Calculation 236-A-DC, “Unit 1 Battery Charger Sizing Calculation for Battery Charger 11,12,121,131,and 132," Revision 1, which took credit for a maximum charger capability of 110 percent of the full load rating of 400 amps (440 amps). In the Final Safety Analysis Report sections for the battery chargers, the chargers were set at sufficient capacity to carry loads up to 110 percent of its 400 ampere rating and were set to a current limit of 110 percent of rated output current. However, the NRC noted that Maintenance Procedure MP E-67.3A, "Routine Preventive Maintenance of Batteries," set the current limit to 430 amps (107.5 percent of full load amps). The NRC determined that at the setting of 107.5 percent, the battery charger had adequate capability to supply the DC loads for analyzed accident scenarios. However, the NRC found that the 107.5 percent battery charger setting was not in agreement with calculation assumptions.

The NRC determined that the battery float voltage setting was 135 volts plus control tolerances which would allow it to be as high as 135.9 volts. The battery vendor manual specified a nominal float voltage of 2.20 to 2.25 volts per cell, which was 132 to 135 volts for the 60-cell vital batteries. The NRC identified that the use of a potentially higher battery float voltage (135.9 volts) than that specified by the vendor (135 volts maximum) could result in the baking of normally energized dc coils. This could shorten the usable life of the equipment.

The NRC found that the licensee selected a nominal equalize voltage of 138 volts. The vendor recommended an equalizing charge range of 139.8 to 142.8 volts for 60 cells. The NRC noted that setting the equalize level at 138 volts had no serious consequences except to reduce the effectiveness of the equalization.

Inspection Followup

The inspectors reviewed the licensee's response to the inspection findings transmitted in Letter DCL-98-007 to the NRC, dated January 12, 1998. The licensee stated that the purpose of Calculation 236A-DC, Revision 1, was to establish that the sizing of the battery chargers was adequate to supply the existing DC connected loads and recharge the battery within 12 hours. The licensee stated that the conclusions of the calculation, which specified the maximum battery charger load as 316 amps, meant that the nominal setting of 430 amps in Maintenance Procedure E-67.3A was acceptable by a large margin. In addition, the licensee stated that the Final Safety Analysis Report statements were meant to describe battery charger capacity ratings, but noted that these statements could be inferred to be specified settings. The licensee stated that they would review and clarify these statements in the Final Safety Analysis Report by April 1, 1998.

The inspectors reviewed Calculation 236A-DC and verified that the maximum charger load was 316 amps. The inspectors determined that the battery chargers were operable since the maximum charger load of 316 amps was less than the nominal setting of 430 amps specified in the maintenance procedure.

The licensee agreed that if the battery float voltage was too high it could tend to bake normally energized dc coils. However, the licensee stated that the advantage of reducing the number of equalization cycles outweighed the negligible effect of the small 0.9 V difference between the maximum set voltage and the maximum value of the manufacturers range. The licensee stated that operating experience showed that neither battery life nor capacity was affected by operation with the existing float voltage. In addition, the licensee had not noted an excessive number of dc coils failing. The inspectors reviewed Action Request A0444410, dated September 25, 1997, which was initiated in response to this inspection finding. As part of the corrective actions, the licensee revised the weekly surveillance test procedure to tighten the float voltage tolerance from 135 +/- 0.9 V to 135 +/- 0.5 V. The inspectors reviewed Surveillance Test Procedure STP M-11A, "Measurement of Station Battery Pilot Cell Voltage and Specific Gravity," Revision 12, and verified that the tolerance band of the float voltage was revised to 135 +/- 0.5 V. The inspectors determined that the voltage setting was acceptable.

The licensee stated in their response letter that operating experience had shown that the charger equalizing voltage field setting of 138 V was adequate to restore the battery to normal parameters, despite being below the recommended range. The inspectors reviewed Surveillance Test Procedure Basis Document B-STP M-11B, “Basis Document for STP M-11B Measurement of Station Battery Voltage and Specific Gravity”, Revision 0, which contained the basis for the field setting, and concurred with the licensees conclusions. The licensee stated that the normal equalizing field setting of 138 Vdc would not be revised. The inspectors considered the licensee's decision to be acceptable.

E8.21 (Open) Unresolved Item 50-275/97202-10: Potential USQ and Technical Specification Adherence Associated With Containment Spray During Containment Recirculation

Background

In 1991, the licensee discovered that, in an accident, the maximum heat load, and hence the maximum temperature, in the CCW system would occur during the recirculation phase rather than the injection phase. This was due primarily to the higher combination of heat loads from the residual heat removal system and the containment fan coolers during this phase as opposed to just the containment fan coolers heat load during the injection phase. This had the potential to cause CCW temperature to exceed its design limits of 120°F for continuous operation and 132°F for up to 20 minutes. On January 17, 1992, Licensee Event Report (LER) 1-91-018 was issued to document this discovery.

Corrective actions included revising Emergency Operating Procedure E-1.3, "Transfer to Cold Leg Recirculation," Revision 13, to include steps to assure maximum heat transfer to the UHS (two ASW pump/two CCW heat exchangers), and if this configuration could not be established by the time of realignment for cold-leg recirculation to assure that only one residual heat removal system pump was left in service providing reactor coolant system (RCS) injection. Containment spray from residual heat removal was to be terminated during this phase for this condition. Corrective actions also included changing the Final Safety Analysis Report to reclassify recirculation spray as nonsafety related.

In reviewing this issue, the licensee also discovered that, for a single failure that would incapacitate one of the residual heat removal pumps, the same condition of not having recirculation spray through residual heat removal would exist. However, this discovery was not included in LER 1-91-018, and it was never formally reported to the NRC in any other manner.

The licensee's review determined that operation without residual heat removal recirculation spray was technically acceptable because:

1. There were no increases in offsite or control room doses since iodine was completely removed from the containment atmosphere by the containment spray system during the injection phase.

2. Peak containment pressure was reached during the injection phase, and long-term pressure was maintained by the containment fan coolers without the use of recirculation spray.

3. Although the long-term temperature/pressure profiles were altered without recirculation spray, they were still enveloped by the profiles used for environmental qualification of equipment in the containment.

4. Containment sump pH was not affected since all of the NaOH in the spray additive tank was injected into the containment by the containment spray system during the injection phase.

5. Long-term hydrogen mixing was completely accomplished by the containment fan coolers, and therefore there was no dependence on recirculation spray to achieve this mixing.

However, this mode of post-accident operation was contrary to the Final Safety Analysis Report at that time. Final Safety Analysis Report, Section 6.2.3.2.1, stated, "During the recirculation phase following a postulated LOCA, containment spray water is provided by recirculation of water from the containment sump through the residual heat removal pumps and piping that connects the residual heat removal pump discharge to the containment spray header. This mode of operation will be continued for a period of at least 2 hours following the accident to continue iodine removal from the containment atmosphere." In their corrective actions, the licensee intended to eliminate this Final Safety Analysis Report requirement for recirculation spray for 2 hours.

In issuing Revision 9 of Emergency Operating Procedure E-1.3 to address this discovery, the licensee's screening process incorrectly determined that a 10 CFR 50.59 safety evaluation was not required. However, a subsequent safety evaluation performed by Westinghouse determined that the emergency operating procedure revision did not involve an unreviewed safety question (USQ).

At the time of discovery, the licensee considered one residual heat removal pump insufficient to provide both the RCS injection and recirculation spray functions, although there was no calculation to support that conclusion. However, during the previous inspection (the inspection during which this item was identified), the licensee performed Calculation STA-075, "Minimum ECCS Flow and Minimum Recirculation Spray Header Flow," Revision 0, which demonstrated that one residual heat removal pump could perform both functions if RCS injection flow was reduced. This would require operator action to throttle the residual heat removal injection valves. This reduced R.C.S. injection flow had been demonstrated as acceptable by Westinghouse analysis NSAL 95-001, dated January 20, 1995, "Minimum Cold Leg Recirculation Flow - ECCS Analysis."

Additionally, during the previous inspection, because of NRC concerns, the licensee prepared a new consolidated safety evaluation. This safety evaluation again concluded that none of the changes that had been made constituted a USQ.

At the conclusion of the previous Inspection, the NRC team concluded the following:

1. The licensee incorrectly performed the 10 CFR 50.59 safety evaluation screening of Revision 9 to Emergency Operating Procedure E-1.3, and as a result, had not performed a safety evaluation as required by 10 CFR 50.59.

2. Although a safety evaluation had subsequently been performed by Westinghouse, it incorrectly concluded that this change and the Final Safety Analysis Report change to eliminate the 2-hour recirculation spray requirement were not a USQ.

3. The new safety evaluation also incorrectly concluded that the changes did not involve a USQ.

Inspection Followup

The licensee responded to the NRC's concerns in a letter to the NRC, DCL-98-007, dated January 12, 1998. In this letter they stated again that they considered their actions appropriate, and that the emergency operating procedure and Final Safety Analysis Report changes that were made as a result of this discovery had not involved a USQ. The following reasons were given for their conclusion:

1. The containment spray (CS) function during the recirculation phase was not required for CS operability by either the licensing or design bases.

2. The technical specification requirement to demonstrate the capability to spray containment using the residual heat removal system involved only demonstrating that the valves connecting the residual heat removal system to the containment spray rings could be opened.

3. The 10 CFR 50.59 safety evaluation screening on the emergency operating procedure change was performed with the knowledge that the outcome of the operability evaluation performed found the affected systems to be operable. However, it was acknowledged that recent NRC guidance would lead a reviewer to conclude that a safety evaluation would have been required.

The licensee also prepared a "white paper" entitled, “Containment Spray in Post-LOCA Recirculation - Licensing and Design Basis History at the Diablo Canyon Nuclear Power Plant," Revision 1, October 7, 1997 and the above-described new 10 CFR 50.59 safety evaluation in which they documented the bases for their conclusions that the changes did not involve a USQ.

The licensee conceded that several errors and omissions occurred during the revision and review processes for the emergency operating procedures, Final Safety Analysis Report, and other documents. While these documents were being corrected, the licensee still concluded that their original evaluation, that these changes involved no USQ, was still valid.

The licensee also maintained that the limitations on the use of recirculation spray with only one residual heat removal pump available were not addressed in the Final Safety Analysis Report because the accident analysis in Section 6.2C.4.2 of the Final Safety Analysis Report stated that no credit was taken for recirculation spray.

The inspectors reviewed all of these documents, as well as the specific requirements of 10 CFR 50.59 in light of current NRC practice and interpretations. The inspectors found that the original 10 CFR 50.59 safety evaluation screening for the emergency operating procedure change erroneously concluded that a safety evaluation was not required. However, in view of the relatively early date of that screening, the fact that a safety evaluation was performed by Westinghouse shortly after the procedure was issued, and the licensee's acknowledgment of that error and recognition that in today's environment a safety evaluation would be required, the inspectors did not consider this to be a significant concern.

The inspectors considered that one provision of 10 CFR 50.59 had apparently not been correctly evaluated. This provision stated that "A proposed change...shall be deemed to involve an unreviewed safety question...(ii) if a possibility for an accident or malfunction of a different type than any evaluated previously in the safety analysis report may be created...." For certain single failures, with the procedural guidance that then existed, residual heat removal recirculation spray would not have functioned as described in Final Safety Analysis Report Section 6.2.3.2.1. This discovery constituted a "defacto "change to the facility as described in the safety analysis report. This change also created, and, in fact, was, a malfunction (failure of the residual heat removal system to provide recirculation spray) of a different type than any evaluated previously in the Final Safety Analysis Report. That is, the Final Safety Analysis Report had not previously evaluated the possibility of malfunction of recirculation spray through the residual heat removal system. Although calculations existed that showed that recirculation spray was not required, the inspectors concluded that this was not relevant to the USQ question.

This issue will remain open pending further review by the NRC.

Conclusions

The discovery of a design vulnerability that could result in loss of containment spray during the recirculation phase (of a loss of coolant accident recovery) appeared to constitute an unreviewed safety question. This unresolved item was left open pending additional review by the NRC.

V. Management Meetings

XI Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management by telephone on March 18, 1998. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. The licensee stated that some information reviewed by the inspectors was proprietary. This information was not discussed in the report.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

S. Ketelsen, Supervisor, Licensing
D. Brosnan, Supervisor, Licensing
B. Waltos, Assistant Manager, Engineering
J. Kelly, Engineer
B. McCoy, Senior Engineer
B. Powers, Vice President and Plant Manager
R. Klimczak, Supervisor, Nuclear Technical Services
J. Shoulders, Director, Nuclear Technical Services
T. Fetterman, Director, Instrumentation and Control/Electrical, Nuclear Technical Services
D. Vosburg, Director, Nuclear Safety Systems/Structures, Nuclear Technical Services

NRC

D. Allen, Resident Inspector
D. Prouix, Senior Resident Inspector

INSPECTION PROCEDURES USED

92903 Followup-Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-275;323/9805-01	IFI	ASW System Suction Vulnerability to Single Failure

Closed

50-275/9517-01	IFI	Design of the 4kV to 480V Safety Related Transformer
50-323/9613-01	VIO	Failure to Have Adequate Fire Protection Material Control
50-275/9613-02	IFI	Adequacy of the Operability-ASW Buried Piping
50-275;-323/9623-07	VIO	PSRC did not Review Safety Evaluations as Required by TS
50-323/9624-03	VIO	Failure to Perform 50.59 Evaluation Prior to Changing U2 Trip Set Point

50-275/9703-03	VIO	Failure to Take Adequate Corrective Actions-Water in the Turbine
50-275;323/9717-01	VIO	Failure of FP- Correct the Lack of Smoke Detector Sensitivity Testing
50-275;-323/9717-02	VIO	Failure to Control Transient Combustible Materials
50-275/96-013-01	LER	MSSV Set Outside TS 3.7.1.1
50-275/96-007-01	LER	TS 3.7.1.1 Not Met- High MSSV Lift Points
50-275/9612-01	DEV	History of Diablo MSSVS
50-275/97202-01	IFI	Review UHS Calc for Max UHS Temp Plant Operating Without Exceeding ASW DSN
50-275/97202-02	IFI	Review Rev to WCAP 14282
50-275/97202-05	URI	Discrepancy In Design Documentation
50-275/97202-06	URI	Availability of Alternate Flowpath for the ASW System Suction
50-275/97202-07	URI	EDG Transient Analysis Computer Simulation Study
50-275/97202-08	IFI	Control of Calculations
50-275/97202-09	IFI	Review of Battery Charger Settings

<u>Discussed</u>

50-275/97202-03	URI	Determine if Long-Term Post-LOCA Operation of ASW with Trains Tied Is USQ
50-275/97202-04	IFI	ASME Section XI Testing of ASW Pumps
50-275/97202-10	URI	Potential USQ and TS Adherence Associated With Containment Spray

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater System
DCN	Design Change Notice
LBIE	Licensing Basis Impact Evaluation
LER	Licensee Event Report
NFPA	National Fire Protection Association
PSRC	Plant Staff Review Committee
SER	Safety Evaluation Report
TSI	Technical Specification Interpretation
USQ	Unreviewed Safety Question
CS	Containment Spray
ASW	Auxiliary Saltwater
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
RCS	Reactor Coolant System
LDBAP	Licensing and Design Basis Alignment Program
ITS	Improved Technical Specifications
CCW	Component Cooling Water

NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-8064

AUG 2 8 2000

Gregory M. Rueger, Senior Vice
President, Generation and Chief Nuclear Officer
Pacific Gas and Electric Company
Diablo Canyon Power Plant
P.O. Box 3
Avila Beach, CA 93424

SUBJECT: Diablo Canyon - NRC INSPECTION REPORT NO. 50-275/00-11; 50-323/00-11

Dear Mr. Rueger:

On August 10, 2000, the NRC completed an inspection at your Diablo Canyon Nuclear Power Plant, Units 1 and 2, facilities. The results of this inspection were discussed on August 10, 2000, with Mr. Larry Womack and other members of your staff.

This inspection was an examination of activities conducted under your license as they relate to the design adequacy and performance capability of the auxiliary saltwater and 4160 Vac systems and their support systems. Within these areas, the inspection consisted of a selected examination of procedures and representative records, observations of activities, and interviews with personnel. Within the scope of the inspection, no findings were identified.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of N RC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

Jeffrey L. Shackelford, Chief
Engineering and Maintenance Branch
Division of Reactor Safety

Docket Nos.: 50-275; 50-323
License Nos.: DPR-80; DPR-82

Enclosure:
NRC Inspection Report No.
50-275/00-11; 50-323/00-11

cc w/enclosure:
David H. Oatley, Vice President
Diablo Canyon Operations and Plant Manager
Diablo Canyon Nuclear Power Plant
P.O. Box 56
Avila Beach, California 93424

Lawrence F. Womack, Vice President, Power
Generation & Nuclear Services
Diablo Canyon Power Plant
P.O. Box 56
Avila Beach, CA 93434

Dr. Richard Ferguson
Energy Chair
Sierra Club California
1100 11th Street, Suite 311
Sacramento, California 95814

Nancy Culver
San Luis Obispo Mothers for Peace
P.O. Box 164
Pismo Beach, California 93448

Chairman
San Luis Obispo County Board of
Supervisors
Room 370
County Government Center
San Luis Obispo, California 93408

Truman Burns\Mr. Robert Kinosian
California Public Utilities Commission
505 Van Ness, Rm. 4102
San Francisco, California 94102

Robert R. Wellington, Esq.
Legal Counsel
Diablo Canyon Independent Safety Committee
857 Cass Street, Suite D
Monterey, California 93940

Ed Bailey, Radiation Program Director
Radiologic Health Branch
State Department of Health Services
P.O. Box 942732 (MS 178)
Sacramento, CA 94327-7320

Steve Hsu
Radiologic Health Branch
State Department of Health Services
P.O. Box 942732
Sacramento, California 94327-7320

Christopher J. Warner, Esq.
Pacific Gas and Electric Company
P.O. Box 7442
San Francisco, California 94120

City Editor
The Tribune
3825 South Higuera Street
P.O. Box 112
San Luis Obispo, California 93406-0112

Robert A. Laurie, Commissioner
California Energy Commission
1516 Ninth Street (MS 31)
Sacramento, CA 95814

ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.	50-275; 50-323
License Nos.:	DPR-80; DPR-82
Report No.	50-275/00-11; 50-323/00-11
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Nuclear Power Plant, Units 1 and 2
Location:	7 1/2 miles NW of Avila Beach Avila Beach, California
Dates:	July 24 through August 11, 2000
Team Leader:	C. J. Paulk, Senior Reactor Inspector Engineering and Maintenance Branch
Inspectors:	C. A. Clark, Reactor Inspector Engineering and Maintenance Branch
	P. A. Goldberg, Reactor Inspector Engineering and Maintenance Branch
	W. M. McNeill, Reactor Inspector Engineering and Maintenance Branch
	N. L. Salgado, Resident Inspector Projects Branch D
Accompanying Personnel:	R. Quirk, Consultant
Approved By:	Jeffrey L. Shackelford, Chief Engineering and Maintenance Branch Division of Reactor Safety

ATTACHMENTS:

Attachment 1	Supplemental Information
Attachment 2:	NRC's Revised Reactor Oversight Process

SUMMARY OF FINDINGS

I R 05000275-00-11; 05000323-00-11; on 07/24-08/11/00; Pacific Gas and Electric Company; Diablo Canyon Power Plant; Units 1 & 2; Inspection of Safety System Design and Performance Capability Report; No Findings Identified.

This report covers a 2-week onsite inspection by a team of five Region IV inspectors and one contractor. The report includes the results of a safety system design and performance capability team inspection of the auxiliary saltwater and 4160 Vac systems and their supporting systems. No issues were identified during the inspection.

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

- No findings were identified.

Report Details

1 **REACTOR SAFETY**

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1 R21 Safety System Design and Performance Capability

.1 System Requirements

a. Inspection Scope

The team reviewed operator actions and procedures associated with the auxiliary saltwater and 4160 Vac systems to ensure that they could be relied upon to meet their functional requirements. This review consisted of system walkdowns; review of normal operating, annunciator response, off-normal, and emergency operating procedures; and review of the Final Safety Analysis Report Update, the technical specifications, the system design criteria, and plant drawings. The purpose of this review was to verify that the auxiliary saltwater system, the 4160 Vac system, and appropriate support systems would perform the functions that were assumed to be available in the safety analysis.

The team reviewed the process media required for the operation of the auxiliary saltwater system. These media included the water, electrical, and air supplies for the auxiliary saltwater system; and the supply of auxiliary saltwater to the component cooling water heat exchangers. The review included piping and instrumentation diagrams, operating procedures, calculations, the Final Safety Analysis Report Update, system descriptions, and design bases documents. This review was performed to verify that the process media will be available and unimpeded during accident or event conditions.

The team verified that the system needs for the emergency diesel generators were met. The supply of air and the required amount of clean and tested diesel fuel and lubricating oil required by the technical specifications were verified through a review of the design of the emergency diesel generators' air start system, fuel oil storage and transfer system, lubricating oil storage system, and the licensee's fuel oil testing program.

The team reviewed the licensee's program for chemical analysis and treatment of the auxiliary saltwater system, as well as, the cleaning and testing requirements for the component cooling water heat exchangers. The existence of corrosion control and testing programs identified in the licensee's response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," was reviewed on a sampling basis. Applicable condition reports and maintenance action items were reviewed to verify that problems with system needs were being identified and addressed.

The team reviewed the availability of the ac and dc power supply systems; minimum voltage requirements; system grounding requirements; the design requirements of the auxiliary saltwater pumps' motors; equipment cables; circuit breakers and protective devices; and emergency diesel generators and fuel storage.

b. Issues and Findings

No findings were identified.

.2 System Condition and Capability

a. Inspection Scope

The team reviewed system operations for the auxiliary saltwater and 4160 Vac systems and their required support systems. This review consisted of system walkdowns; review of normal operating, annunciator response, off-normal, and emergency operating procedures; and review of the Final Safety Analysis Report Update, the technical specifications, the system design criteria, and plant drawings.

The team reviewed the environment and environmental qualification of equipment in the auxiliary saltwater pump rooms and the emergency diesel generator rooms to verify that the equipment was qualified to perform its intended function when required, subject to the assumed accident environment.

The team performed a walkdown of the auxiliary saltwater system: auxiliary saltwater pump rooms, and the 4160 Vac system to verify that the changes and modifications to the initial design had not affected or changed the system design bases or required functional performance. The team used design drawings, piping, isometric and diagram drawings to assist in the as-built verification walkdowns.

The team verified that required inputs to components, such as flow, pressure, and temperature parameters, were consistent with design basis analyses for the auxiliary saltwater and 4160 Vac systems and their support systems.

Through a review of historical and current maintenance records including performance tests, the team evaluated for signs of degradation of the auxiliary saltwater and 4160 Vac systems and support system components.

b. Issues and Findings

No findings were identified.

.3 Identification and Resolution of Problems

a. Inspection Scope

The team reviewed a sample of auxiliary saltwater and 4160 Vac systems and support systems design-related problems identified by the licensee's corrective action program.

The team also reviewed Procedure OM7.ID1, "Problem Identification and Resolution – Action Requests," Revision 12.

The team reviewed the actions the licensee has taken in response to industry-identified problems with the auxiliary saltwater and 4160 Vac systems and support equipment. This review included the status of modifications to replace 4160 Vac General Electric Magnablast circuit breakers.

b. Issues and Findings

No findings were identified.

.4 System Walkdowns

a. Inspection Scope

The team performed walkdowns of the accessible portions of the auxiliary saltwater piping and 4160 Vac systems, as well as the required support systems. The walkdowns focused on the installation and configuration of piping, components, and instruments; the placement of protective barriers and systems; the susceptibility to flooding, fire, or other environmental concerns; the physical separation; the provisions for seismic concerns; accessibility for operator action; and the conformance of the currently installed configuration of the systems with the design and licensing bases.

b. Issues and Findings

No findings were identified.

.5 Design Review

a. Inspection Scope

The team reviewed the design criteria for the auxiliary saltwater and 4160 Vac systems and then selected specific design criteria that assured the performance of safety functions during accident conditions. These criteria were reviewed to determine whether the design bases of the systems were met by the currently installed and tested configurations. Document reviews included drawings, procedures, calculations, vendor specifications, condition reports, and maintenance action items identified in the attachment, as well as the facility technical specifications and the Final Safety Analysis Report Update. These reviews further addressed the validity of design assumptions and calculations.

The team also assumed specific failures of individual safety- and nonsafety-related components to determine the potential effects of such failures on the capability of the systems to perform their safety functions. Instrumentation was reviewed to verify the appropriateness of setpoints with regard to the parameters that were monitored or measured and the function that was affected by or related to the monitored parameter.

Additionally, the team performed analyses in several areas to verify that design values were correct and appropriate.

b. Issues and Findings

No findings were identified.

.6 Safety System Testing

a. Inspection Scope

The team reviewed the program, procedures, and records associated with testing, cleaning, and inspecting the component cooling water heat exchangers and the auxiliary saltwater traveling screens. The team also verified that procedures, policies, and appropriate program requirements were in place to perform all technical specification required surveillance testing or monitoring for the auxiliary saltwater and 4160 Vac systems. This included a review of required inservice testing of pumps and the NRC - granted exemptions for cases where ASME Section XI code requirements for testing were not met. Additional review was performed to verify that installed or test instrument uncertainties and system conditions that degrade safety system performance (e.g., heat exchanger fouling factors) were appropriately accounted for within the testing and analysis methodologies.

b. Issues and Findings

No findings were identified.

4 OTHER ACTIVITIES (OA)

40A6 Management Meetings

.1 Exit Meetinq Summary

The inspectors presented the inspection results to Mr. Larry Womack and other members of licensee management at the conclusion of the onsite inspection on August 10, 2000. The licensee's management acknowledged the findings presented.

The inspectors asked the licensee's management whether any materials examined during the inspection should be considered proprietary. While the licensee's representatives noted that some proprietary information had been reviewed by the team, no proprietary information is contained in this report.

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Anastasio, Engineer, Engineering Services
J. Becker, Manager, Operations Services
S. Chesnut, Director, Balance of Plant
D. Christensen, Engineer, Nuclear Safety and Licensing
K. Kaminski, Engineer, Engineering Services
D. Miklush, Manager, Engineering Services
J. Portney, Senior Engineer, Engineering Services
J. Tompkins, Manager, Nuclear Safety and Licensing
D. Vosburg, Director - Nuclear Steam System, Engineering Services
L. Womack, Vice President, Power Generation and Nuclear Services

NRC

D. Proulx, Senior Resident Inspector, Diablo Canyon Power Plant

DOCUMENTS REVIEWED

Procedures

NUMBER	DESCRIPTION	REVISION
17.8	- Preoperational test of auxiliary saltwater system	September 7, 1982
AR PD01-01	Annunciator response procedure asw sys delta P/HDR Pressure	20A
AR PK01-01	ASW SYS HX DeltaP/HDR Press	20A
AR PK01-02	Aux Salt Wtr PPS Room	10A
AR PK01-03	Aux Saltwater Pumps	11
AR PK01-06	CCW Vital HDR A/B	17
AR PK13-01	Bar Racks/Screens	16
AR PK16-16	4kV Bus H DIFF Lockout	6A
AR PKII 6-17	4kV Bus H Bus or SU FDR UV	9A
AR PK16-18	4kV Bus H DC Control UV/Trouble	9
AR PKII 6-19	4kV Bus H Auto Transfer	6

Procedures

NUMBER	DESCRIPTION	REVISION
AWP E-001	Development of Performance Measurement Equipment Channel Uncertainty Calculations	OA
CF3.DC5	Development of I&C Scaling Calculations	OA
CF5.ID1 1	Lubricant Storage, Selection, Dispensing, and Use	1
EOP ECA-0.0	Loss Of All Vital AC Power	13
EOP ECA-0.3	Restore 4kV Buses	9
LT 17-8A	Traveling Screens and Bar Racks Level Channel Calibration	4
LT 17-8D	Aux Saltwater Pump Intake Bay 1-7 Level Channel LT-240C Calibration	3
LT 17-8D	Auxiliary Saltwater Pump Intake Bay 1-7 Level Channel LT-240C Calibration	3
LT 17-23A	Auxiliary SWP 2-1 Bay Level Channel Calibration	1
MP E-50.308	Agastat Type ETR Timing Relay Maintenance	8
MP E-50.3013	AGASTAT Type ETR Timing Relay Maintenance	8
MP E-56.1	Electrical Equipment Lubrication Chart	3
MP E-63.313	Maintenance of Potential Transformer Drawers in General Electric Metal-Clad 4kV and 12 kV Switchgear	5A
MP E-63.3C	Maintenance of 4 and 12 kV Switchgear	8
MP E-63.3D	4 & 12 kV Switchgear Bus Connection Resistance Test	1
MP E-63.6A	Maintenance of SF6 4kV Circuit Breakers	7
NSP-1-17-15A	Nominal Setpoint Calculation for the CCW Heat Exchanger Low DP Alarm	5
NSP-1-17-16A	Auxiliary Saltwater Pump Low Discharge Pressure Switches	1
OM4.ID3	Assessment of Industry Operating Experience	4
OM7.ID1	Problem Identification and Resolution - Action Requests	12
OM7.ID2	Qualitv Evaluations	9

Procedures

NUMBER	DESCRIPTION	REVISION
OM7.ID3	Nonconformance Report (NCR) and Technical Review Group (TRG)	8
OM7.ID10	Quality Trend Analysis Program	6
OP AP SD-1	Loss of AC Power	11
OP AP SD-3	Abnormal Operating Procedure Loss of Auxiliary Salt Water	7A
OP AP-10	Abnormal Operating Procedure Loss of Auxiliary Salt Water	7
OP AP-1 1	Abnormal Operating Procedure Malfunction of Component Cooling Water System	17
OP AP-26	Loss of Offsite Power	3
OP J-6A	4160 Volt System	6A
OP J-6A:	4160 Volt System - Make Available	9
OP J-6A: 11	Transferring 4160 Volt Banks	6
OP J-6A: IV	4160 Volt Breaker Code Order	14
PEP EN-1	Emergency Engineering Guideline on Control Room EOP Consultation	5/5/99
Round Sheet 69-11829-6	Intake Structure/Outside Services Weekly Round Sheet	18
STP I-1C	Routine Weekly Checks	68
STP M-13A	Manual and Auto Transfer of 4kV Vital Busses Off-Site Power Sources	9A
STP M-13133	ENGD SFGDS Auto Timers Setting VERF Loads Started SSPS Relay K-609, Train A	7
STP M-13134	ENGD SFGDS Auto Timers Setting VERF Loads Started SSPS Relay K-609, Train B	7
STP M-1 3F	4kV Bus F Non-SI Auto-Transfer Test	24
STP M-13F	4kV Bus F Non-SI Auto-Transfer Test	24
STP M-13G	4kV Bus G Non-SI Auto-Transfer Test	18
STP M-1 3H	4kV Bus H Non-SI Auto-Transfer Test	18

Procedures

NUMBER	DESCRIPTION	REVISION
STP M-15	Integrated Test of Engineered Safeguards and Diesel Generators	34
STP M-16	Safeguards Active Component Operation By Slave Relay Operation	9
STP M-16E	Operation of Train A Slave Relays K609 (Safety Injection) K633 (Motor Driven AFW Pump Start)	11
STP M-16F	Operation of Train B Slave Relays K609 (Safety Injection) K633 (Motor Driven AFW Pump Start)	12
STP M-235	Auxiliary Salt Water Piping Inspection	2
STP M-26	Auxiliary Salt Water System Flow Monitoring	23
STP M-26A	FCV-601, Auxiliary Salt Water Unit 1 and 2 Cross-Tie Dividing Valve, Flow Test	10
STP M-75	4kV Vital Bus Undervoltage Relay Calibration	23
STP M-90A	Monthly Surveillance of Diablo Canyon Breakwaters	2
STP M-90B	Annual Surveillance of Diablo Canyon Breakwaters	2
STP M-1 09	Test of Backup Air Accumulator System to Fcv-602, CCW Heat Exchanger No. 1 Saltwater Inlet Valve	8
STP M-1 10	Test of Backup Air Accumulator System to FCV-603, Component Cooling Water Heat Exchanger No. 2 Saltwater Inlet Valve	8
STP P-ASW-1 1	Routine Surveillance Test of Auxiliary Saltwater Pump 1-1	15
STP P-ASW-12	Routine Surveillance Test of Auxiliary Saltwater Pump 1-2	1
STP P-ASW-21	Routine Surveillance Test of Auxiliary Saltwater Pump 2-1	14
STP P-ASW-22	Routine Surveillance Test of Auxiliary Saltwater Pump 2-2	11
STP P-ASW-A	Performance Test of Auxiliary Saltwater Pumps	11,12
STP P-CCW-1 1	Routine Surveillance Test of Component Cooling Water Pump	10

Procedures

NUMBER	DESCRIPTION	REVISION
STP P-CCW-12	Routine Surveillance Test of Component Cooling Water Pump 1-2	7
STP P-CCW-13	Routine Surveillance Test of Component Cooling Water Pump 1-3	7
STP V-2A1	Auxiliary Saltwater Cross Connect Header Valves	1
STP V-2A2	Auxiliary Saltwater Crosstie Valve FCV-601	3
STP V-2A3	Auxiliary Saltwater Demusseling Valves	1
STP V-2F	Component Cooling Water Valves	7
STP V-3F1	Exercising Valve FCV-495, ASW Pump 2 Crosstie Valve	15,16
STP V-3F2	Exercising Valve FCV-496, ASW Pump 1 Crosstie Valve	14,15
STP V-3F3	Exercising Valve FCV-601, Units 1 and 2 ASW Crosstie	15
STP V-3F4	Exercising Valve FCV-602 CCW HX No. 1 Saltwater Inlet	14,15
STP V-3F5	Exercising Valve FCV-603 CCW HX No. 2 Saltwater Inlet	12,13
STP V-31-18	Exercising FCV-430 & FCV-431, CCW Heat Exchanger Outlet Isol Valves	16

Calculations

NUMBER	DESCRIPTION	REVISION
11 4-DC	Protection Relay Settings for Bus and Feeders	8
170-DC	Overcurrent Relay Setting for Class 1 E, 4 kV Motors	15
174A-DC	Diesel Start and Load Shed First Level Undervoltage Relay Setpoint Calc	1
174B	Second Level Undervoltage Relay Settings	1
215-DC	Emergency Diesel Generator Loading Capability Study without KWS Relay	2
311 -DC	Cable Sizing - 4.16kV Class 1 E Loads	4
340-DC	Intake Structure Cable Ampacity	0

Calculations

NUMBER	DESCRIPTION	REVISION
357A-DC	DCPP Units 1 & 2 Load Flow, Short Circuit, and Transient Stability	3
357M-DC	FLUR and SLUR Drift Analysis	1
357P-DC	SLUR Relay and Timer Setpoints	0
360-DC	125 VDC System Analysis Methodology & Scenario Development	2
D. 1	DCPP Support System Event Trees	8
D.2.1.3	Electric Power Unit 1 Vital AC System	6
D.2.1.4	Electric Power Vital AC/DC System Unit 2	6
D.2.6	Auxiliary Saltwater Systems Analysis	6 and 7
EQP 301.1	Deflection of Impeller Shaft	May 18, 1988
J-002	Backup Air/nitrogen Accumulators and Bottles	6
M-9	Backup Air Supply, to Size Receivers	4
M-1 88	To Determine the Velocity of Slat Water Through the CCW Heat Exchanger under Design and Maximum Flow	2
M-370	Determine the Thrusts from the Auxiliary Saltwater Lines on the CCW Heat Exchangers for Units 1 & 2	May 23, 1983
M-854	Worst Case Brake Horsepower for AFW, ASW, and CCW Pumps	3
M-897	CCW Flow Balance	4
M-917	Determine the ASW Flows for Various Configurations Utilizing the Inter-unit Crosstie Piping	3
M-938	CCW Date Input for 1993 Containment Analysis Program	3
M-953	Determine If Adequate NPSH Is Available for 1 Pump Supplying 2 Heat Exchangers	January 17, 1994
M-966	Establish Maximum CCW Flow Rate to the RHR Heat Exchangers	August 4, 1994
M-988	To Evaluate the Effects of the New ASW Bypass Piping	6

Calculations

NUMBER	DESCRIPTION	REVISION
M-1017	To Determine Flows in the CCW System	3
M-1 020	Evaluate the CCW System for Mode 4 Operation with Elevated UHS Temperatures	1
M-1027	To Determine the Maximum Allowable ASW Temperature When 2 CCW Heat Exchangers Are Aligned	
NSP-1-17-15	Nominal Setpoint Calculation for the CCW Heat Exchanger D/P Alarm	3
NSP-1-17-16A	Nominal Setpoint Calculation for Auxiliary Saltwater Pump Low Discharge Pressure Switches	1
NSP-1-17-23A	Nominal Setpoint for Auxiliary Saltwater Pump Bay Low Level Alarm	0
PLG 637	Diablo Canyon Probabilistic Risk Assement	July 1988
SC-L-17-15A	Instrument Scaling Calculation CCW Heat Exchanger 1-1 Differential Pressure Channel PT-5 Calibration	2
SC L-17-16A	Instrument Scaling Calculation Auxiliary Salt Water Pumps Header Pressure Switches Calibration	
SC L-17-23A	Instrument Scaling Calculation Auxiliary SWP 1-1 Bay Level Channel LS-163	0
SC L-17-23B	Instrument Scaling Calculation Auxiliary SWP 2-2 Bay Level Channel	0

Drawings

NUMBER	DESCRIPTION	REVISION
053093	Outboard Bubbler for Bar Rack LT-240D, Sheet 50	52
053093	Inboard Bubbler for Bar Rack LT-240D, Sheet 50A	52
053093	Outboard Bubbler for Traveling Screen LT-240B & C, Sheet 50C	28
053093	Inboard Bubbler for Traveling Screen LT-240A, B, & C, Sheet 50D	28

Drawings

NUMBER	DESCRIPTION	REVISION
57554	Cable tray and Conduit Layout Plan Below Elevation 140'-0" Area "A"	30
102017	Piping Schematic Saltwater Systems , Sheet 1	89
102017	Piping Schematic Saltwater Systems, Sheet 3B	87
102017	Piping Schematic Saltwater Systems, Sheet 3	95
102017	Piping Schematic Saltwater Systems, Sheet 5	86
102032	ASW Air Operated Valve Schematic, Sheet 42	143
102032	ASW Air Operated Valve FCV-602, 603 Schematic, Sheet 42E	140
102033	Traveling Screen and Bar Racks Instrument Schematics, Sheet 23C	115
102033	ASW Pump Level Instrument Schematic, Sheet 24A	115
106717	Operating Valve Identification Diagram (OVID), Sheet 1	110
106717	Operating Valve Identification Diagram (OVID), Sheet 7	109
106717	Operating Valve Identification Diagram (OVID), Sheet 8	108
108017	Piping Schematic Saltwater Systems, Sheet 5	53
108017	Unit 2 Saltwater Systems Piping Schematic, Sheet 1	71
108017	Unit 2Screen Wash System Piping Schematic, Sheet 3	71
108017	Unit 2 Aux Saltwater System Piping Schematic, Sheet 3B	73
216191	Screen Wash Pumps and Screen Drive Logic	5
437533	Electrical Single Line Diagram Single Line Meter & Relay Diagram 4160 Volt System	33
437589	Unit S1 Pump Schematic	4
437594	Unit 1 Aux Seawater Pump Schematic	24
437641	Screen Drive Schematic	12
437642	Screen Drive and Wash Schematic	14
437646	Salt Water System Motor Operated Valves FCV-432/433/604/605/495/496/601 Schematic	7

Drawings

NUMBER	DESCRIPTION	REVISION
437681	FCV-602, 603 Schematic	18
441229	4160 V System Bus Section F Single Line	14
441287	Auxiliary Saltwater Pumps Schematic	21
441289	Screen Drive System Schematic	7
490093	Auxiliary Saltwater Pump Intake Level Bubbler L-1 63 Details, Sheet 25	63
502110	Single Line Diagram 500/230/25/12/4.16 kV Systems	10

Action Requests

A0122296	A0467127	A0475431	A0491419	A0504172
A0416737	A0467481	A0475677	A0491977	A0504648
A0419055	A0468144	A0477270	A0492483	A0504915
A0440794	A0468232	A0478268	A0495005	A0505103
A0441048	A0468320	A0478510	A0495066	A0507000
A0448591	A0469102	A0478576	A0495278	A0507382
A0452896	A0469559	A0482690	A0495318	A0508248
A0463722	A0470233	A0482692	A0496068	A0508383
A0463807	A0470978	A0482876	A0496465	A0511800
A0464840	A0471180	A0482901	A0496468	A0511987
A0465134	A0471484	A0483328	A0497475	A0512029
A0465736	A0471662	A0484387	A0500504	A0512581
A0465775	A0472876	A0484806	A0503381	Q0012080
A0465838	A0474755	A0486375	A0503389	
A0466445	A0474805	A0488881		

Design Change Packages

NUMBER	DESCRIPTION	REVISION
A0404677	Teflon coated seat ring installation in Unit 1	November 10, 1999
A0437708	Teflon coated seat ring installation in Unit 2	June 19, 1997
A0475763	Request for design to eliminate ASW vacuum breaker counterweights	January 29, 1999
A0482876	Unit 2 design change to remove counterweights	April 16, 1999

Design Change Packages

NUMBER	DESCRIPTION	REVISION
A0482901	Unit 1 Design Change to Remove Counterweights	April 16, 1999
A0486935	Revise Unit 1 ASW Vacuum Breaker STP Frequency	June 22, 1999
DCO-EM-39834	Increase Impeller Diameter in ASW Pumps	May 20, 1988
E049033	Replace ASW Pump Underground Cable	0
E049318	Replace the Electromechanical First Level Undervoltage Relay (FLUR) with Digital Relays	0
E049451	Raise the Second Level Undervoltage Relay (SLUR) Setpoint	0
M049251	Saltwater- Chemical Biofouling Control Systems Upgrade	1
M049376	Stop Valve in Code Relief Valve Path of CCW Heat Exchanger Should Be Controlled to Ensure Code Compliance	0
M049385	Revise the DCM and FSAR to Reflect ASW Pump Impeller Replacement	0
M050376	Stop Valves in Code Relief Valve Path of CCW Heat Exchanger Should Be Controlled to Ensure Code Compliance	0

Miscellaneous Documents

NUMBER	DESCRIPTION	REVISION
	CCW Heat Exchanger 2-1 Test	February 1998
	Final Unit 2 Ccw Heat Exchanger Test Results	November 22, 1994
	Final Unit 1 CCW Heat Exchanger 1-1 Test Results	April 22, 1996
	Maintenance Rule Data Base	
	Monthly NPQ Quality Problem Reports for August 1999 to July 2000	

Miscellaneous Documents

NUMBER	DESCRIPTION	REVISION
	Remote Internal Video Inspection of ASW Piping During 1 R8 Refueling Outage	June 1997
	Remote Internal Video Inspection of ASW Piping During 2R10 Refueling Outage	April 1998
	Remote Internal Video Inspection of ASW Piping During 1 R7 Refueling Outage	November 1995
	Remote Internal Video Inspection of ASW Piping During 2R7 Refueling Outage	May 1996
	Unit 1 CCW Heat Exchanger Test	April 1995
	Inservice Testing Program Second Ten-Year Interval, UnitsI&2	16
	Supplemental Safety Evaluation of PG&E Response to Station Blackout Rule for Diablo Canyon	May 29, 1992
663030-17	Bingham-Willamette Co. Auxiliary Saltwater Pumps (20 x 34B "VCM" Single Stage Wet Pit Pumps) Vendor Instruction Manual	17
DCM S-17B	Units 1 and 2 Design Criteria Memorandum - Auxiliary Salt Water	16
DCM S-23G	Intake Structure Ventilation System	6
DCM S-63	4160 V System 1	
E-5	Auxiliary Saltwater System	7
GEH-1802	Metal Clad Switchgear Types M-26 and M-36 Instruction and Renewal Parts	U
J-139	Uncertainty in Using the AMAG Ultrasonics Flowmeter for Calibration Checks on the ASW Magnetic Flowmeters	0
J6A	4kV System	8
M-270	Flood Level of the Auxiliary Saltwater Pump Vault Due To Pipe Crack and Floor Drain Plugging	6
M00172080	Repair/Replace PS-185A/185B	

Miscellaneous Documents

NUMBER	DESCRIPTION	REVISION
PG&E 116.30	Asw Pump Testing for Run-out	February 26, 1994
PG&E 116.31	Evaluation of ASW Pumps in a Condition That the Available NPSH Was less than Required	February 9, 1994
PG&E 420DC	Tides Occurring at Diablo Canyon Power Plant	May 4, 1988
PM 51872	CCWHE1 Open Heat Exchanger WaterBoxes (Work Order R0192829 01)	01
PM 53586	CCWHE1 -1 Clean/inspect Seawater Side (Work Order R0088473 01)	01
PM 53601	ASP1 -1 Forebay: Remove Debris (Diver) (Work Order R0192562 01)	01
Report 420DC-97.139	In-place Calibration Verifications of the DCPP Unit 1 ASW Magnetic Flowmeters	August 1997
Report 420DC-00.8	DCPP ASW Magnetic Flowmeter Comparison Tests January - February 2000	March 2000
STP M-13134	Engineered Safeguards Auto Timers Verify Loads Started SSPS Relays K-609 Train B	March 4, 1999
Westinghouse PGE-00-503	RHR Heat Exchanger Flow Increase Evaluation	February 8, 2000
Westinghouse PGE-94-579	Excessive Shell Side Flow Rates for the Residual Heat Exchanger	March 30, 1994

Operating Events Analyses

99-006	99-069	99-120	YO-065
99-035	99-111	99-167	

ATTACHMENT 2

NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety	Radiation Safety	Safeguards
• Initiating Events • Mitigating Systems • Barrier Integrity • Emergency Preparedness	• Occupational • Public	• Physical Protection

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection Findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN Findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE Findings indicate issues that are of low to moderate safety significance. YELLOW Findings are issues that are of substantial safety significance. RED Findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin, but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner, which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.htmi-

July 07, 2010

PG&E Letter DCL-10-073

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20852

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Response to NRC Request for Additional Information for the Diablo Canyon License Renewal Application

Dear Commissioners and Staff:

By letter dated November 23, 2009, Pacific Gas and Electric Company (PG&E) submitted an application to the U. S. Nuclear Regulatory Commission (NRC) for the renewal of Facility Operating Licenses DPR-80 and DPR-82, for Diablo Canyon Power Plant (DCPP) Units 1 and 2, respectively. The application included the license renewal application (LRA), and Applicant's Environmental Report – Operating License Renewal Stage.

By letter dated June 14, 2010, the NRC staff requested additional information needed to continue their review of the DCPP LRA.

PG&E's response to the request for additional information is included in Enclosure 1. LRA Amendment 2 resulting from the responses is included in Enclosure 2 showing the changed pages with line-in/line-out annotations.

PG&E makes no regulatory commitments (as defined in NEI 99-04) in this letter.

If you have any questions regarding this response, please contact Mr. Terence L. Grebel, License Renewal Project Manager, at (805) 545-4160.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on July 07, 2010.

Sincerely,

James R. Becker
Site Vice President

pns/50321512
Enclosure
cc: Diablo Distribution
cc/enc: Elmo E. Collins, NRC Region IV Regional Administrator
Kimberly J. Green, NRC Project Manager, License Renewal
Nathanial B. Ferrer, NRC Project Manager, License Renewal
Michael S. Peck, NRC Senior Resident Inspector
Alan B. Wang, NRC Project Manager, Office of Nuclear Reactor Regulation

PG&E Response to Request for Additional Information For the Diablo Canyon License Renewal Application

RAI B2.1.1-1

Generic Aging Lessons Learned (GALL) Report aging management program (AMP) XI.M1 "scope of program" element contains a broad class of components for inservice inspection (ISI) with respective standards for flaw acceptance and flaw evaluation. Also, the "detection of aging effects" program element covers the inspections of Class 1 small-bore piping and socket welds.

In its description of the ISI program under license renewal application (LRA) Section B2.1.1, the applicant stated that Diablo Canyon Nuclear Power Plant (DCPP) evaluates every indication. However, the acceptance standards IWD-3400 and IWD-3500 and the flaw evaluation standard IWD-3600, for Class 3 components, are not included in the "program description" of LRA AMP B2.1.1. Also, Class 1 small-bore piping and socket welds for the AMP are covered under different AMPs for DCPP.

Explain how the "program description" includes the use of acceptance and evaluation standards for Class 3 components. Also, indicate in which AMP the inspection of Class 1 small-bore piping and socket welds are covered or supplemented, including a justification for using this program.

PG&E Response to RAI B2.1.1-1

LRA Section B2.1.1 has been revised to discuss the acceptance standards IWD-3400 and IWD-3500 and the flaw evaluation standard IWD-3600, for Class 3 components. See revised LRA Section B2.1.1 in Enclosure 2.

Detection of aging effects for Class 1 small-bore piping and socket welds is described in LRA Section B2.1.19, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program." This program is implemented as part of the fourth interval of the DCPP Inservice Inspection (ISI) program. Further information on the basis for using the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program is in the response to RAI B2.1.19-2.

RAI B2.1.1-2

In its "operating experience" summary the applicant noted an instance of intergranular stress corrosion cracking in an accumulator nozzle, identified in 1987, stating that all nozzles were inspected and those with unacceptable indications were subsequently weld-repaired or replaced with nozzles made of a new material. Also, in its evaluation of operating experience the applicant indicated that a long-term inspection plan is followed with visual examination of all nozzles and underskirt piping at normal operating pressure, and ultrasonic testing (UT) of those nozzles and underskirt piping which were not replaced.

The nozzle cracking was not identified as part of the inspections performed under the ASME Section XI ISI program. It is not clear why the UT is not performed on the replacement nozzles as part of the long-term plan, while it is performed on the non-replaced nozzles.

Provide justification for why only a visual inspection is performed on the replaced nozzles and underskirt piping, and not UT, as part of the long-term inspection plan for aging management.

PG&E Response to RAI B2.1.1-2

DCPP accumulators and their nozzles are categorized under IWC-1221(c): "Vessels … and component connections of any size in statically pressurized (i.e., no pumps) safety injection systems of pressurized water reactor plants," and thus are exempted from volumetric and surface examination by Code. Thus the Code requirement for inspection of the accumulators and nozzles is VT-2 during pressure test once each inspection period (40 months).

Beginning in 1986, two of the original nozzles in Unit 2 were observed to have evidence of leakage due to intergranular stress corrosion cracking (IGSCC). These two nozzles were replaced. The analysis performed in 1987 determined that sulfur and chlorine were present at the failure locations. These contaminants apparently originated during the construction hydrostatic tests at the vessel fabricator. All of the original nozzles were 304 grade stainless steel and apparently were installed with partial penetration welds to the shell before the vessels were heat treated, thus potentially being subject to sensitization during both the welding and heat treatment processes.

Ultrasonic and eddy current techniques were developed to detect incipient cracking and together with penetrant tests, all nozzles were inspected in the 4th refueling outage in Unit 2 (2R4), the 5th refueling outage in Unit 1 (1R5), and the 5th refueling outage in Unit 2 (2R5). Twenty-seven nozzles in Unit 2 and 5 in Unit 1 were ultimately found to have indications ranging from obvious cracks to small rounded penetrant indications that would normally be deemed acceptable. Twenty-four of the nozzles were replaced. Some nozzles having minor indications were weld repaired or buffed out.

Replacement nozzles were fabricated from 304L grade stainless steel to reduce susceptibility to IGSCC, and were fillet welded to the vessel shell instead of the original partial penetration welds to the shell. The new nozzles were installed under environmentally controlled conditions to assure absence of sulfur and chlorides. The redesigned weld configuration and lack of contaminants reduces sensitization and susceptibility to ICSCC, thus the new nozzles have been determined not to require ultrasonic monitoring.

PG&E has continued to ultrasonically inspect the original nozzles. No indications have been found since the major repair efforts in 1R5/2R5. The new nozzles are subject to the Code-required periodic pressure test and VT-2 examination once each period (40 months). Additionally, boric acid walkdowns every refueling outage and operator rounds in the containment would detect any leakage at an early stage. No such leakage has occurred.

A visual inspection is adequate to manage the replaced nozzles and underskirt piping since the degradation environment (contaminants, susceptible materials) that caused the original flaws is not present in the new nozzles.

RAI B2.1.3-1

In LRA Section B2.1.3 and a program exception to the GALL Report, the applicant stated, "[t]he future 120-month inspection interval for DCPP will incorporate the then-current requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval." Also, LRA Appendix A, Section A1.3 states, "DCPP is required to update its Section XI ISI program and use the ASME Code Edition consistent with the provisions of 10 CFR 50.55a during the period of extended operation."

The staff determines the acceptability of the newly proposed ASME Code Section XI editions for license renewal in the Statements of Consideration (SOC). The SOC are issued on the update of the 10 CFR 50.55a rule and published in the Federal Register. It is not evident to the staff whether the applicant's statement refers to the SOC associated with the update of 10 CFR 50.55a in order to justify the applicant's use of a more recent edition of the ASME Code Section XI when the plant enters the period of extended operation.

Clarify whether the statement quoted above means that for the future 120-month ISI intervals, which will be implemented during the period of extended operation, the applicant will incorporate the editions and addenda of the ASME Code that will be endorsed for use in 10 CFR 50.55a (as modified and subject to any limitations in rule) and be acceptable for the license renewal as referenced in the SOC on the update of 10 CFR 50.55a and published in the Federal Register.

PG&E Response to RAI B2.1.3-1

LRA Sections A1.3 and B2.1.3 indicate that DCPP is required to update its Section XI ISI program and use the ASME Code Edition consistent with the provisions of 10 CFR 50.55a during the period of extended operation. This means that for the future 120-month ISI intervals, which will be implemented during the period of extended operation, PG&E will incorporate the editions and addenda of the ASME Code that will be endorsed for use in 10 CFR 50.55a (as modified and subject to any limitations in rule) and be acceptable for the license renewal as referenced in the Statements of Consideration on the update of 10 CFR 50.55a and published in the *Federal Register.*

RAI B2.1.3-2

During the audit of the Reactor Head Closure Studs Program (LRA Section B2.1.3), the applicant identified an exception to the "scope of program" program element. The applicant stated that the tensile strength of four heats of the material used in fabricating the studs exceeded the maximum tensile strength limit of 1172 MPa (170 ksi) specified in Regulatory Guide (RG) 1.65, "Material and Inspection for Reactor Vessel Closure Studs," October 1973. The applicant also stated that only heat and charge numbers are marked on the studs, and because there is a significant variation in tensile properties within a Heat and Charge of the material, it is unlikely that DCPP will be able to identify which stud from a given heat has tensile strength greater than 1172 MPa (170 ksi).

In addition to the tensile strength exceeding 1172 MPa, the yield strength of these heats of material exceeded 1034 MPa (150 ksi). For some materials, the yield strength was as high as 1138 MPa (165 ksi). When tempered to a tensile strength level above 1172 MPa, the high strength low-alloy steel for the studs becomes increasingly susceptible to stress corrosion cracking. In NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," June, 1990, the U.S. Nuclear Regulatory Commission established a position that the yield strength of high-strength bolts should not exceed 1034 MPa (150 ksi).

(a) Revise the LRA to include the newly identified exception to GALL "scope of program" program element that identifies that the tensile strength of four of the heats used in fabricating the studs exceeded the maximum tensile strength limit of 1172 MPa (170 ksi) specified in Regulatory Guide (RG) 1.65, "Material and Inspection for Reactor Vessel Closure Studs," October 1973.

(b) In view of the greater susceptibility of some of the studs to SCC, describe any preventive actions taken or planned to avoid the exposure of the studs to the environmental conditions that can lead to SCC, and describe possible changes/modifications in the program for managing cracking due to stress corrosion cracking for reactor head closure studs.

PG&E Response to RAI B2.1.3-2

After submittal of the LRA, Certified Material Test Reports were found to indicate that DCPP has 4 heats that have an average ultimate tensile strength of 170.8 ksi, with a range of 160 ksi to 175.5 ksi. This constitutes an exception to the "scope of program" program element of NUREG-1801, Rev. 1, Section XI.M3. See revised LRA Section B2.1.3 in Enclosure 2.

The DCPP reactor vessel closure studs were fabricated prior to issuance of Regulatory Guide 1.65 and were built in accordance with the required design specifications, SA-540 Grade B-23 and B-24. As described in LRA Section B2.1.3, DCPP manages the reactor head closure studs and bolts for cracking and loss of material through visual and volumetric examinations in accordance with ASME Section XI Subsection IWB requirements and as recommended in Regulatory Guide 1.65.

DCPP reactor vessel closure studs are not metal-plated. DCPP uses "Neolube" and "FelPro N-5000" as lubricant on reactor head closure studs after reactor head closure stud cleaning and examinations are complete. Neolube and FelPro are compatible with the reactor vessel flange, stud, nut, and washer materials at operating temperature.

Reactor vessel flange holes are plugged with water tight plugs during cavity flooding. When the plugs are removed, the threaded holes in the vessel flange are inspected and cleaned if necessary to ensure the bolt holes remain dry. These methods assure the holes, studs, nuts, and washers are protected from borated water during cavity flooding and draining.

If reactor vessel stud, nut, and washer cracking, loss of material, or reactor coolant leakage from the reactor vessel flange is identified, these are evaluated through the DCPP corrective actions program. Corrective actions can include evaluation of adjustment to the stud inspection frequency.

Based on the above information the current program is adequate for managing cracking due to stress corrosion cracking for reactor head closure studs.

RAI B2.1.8-1

In LRA Section B2.1.8, the applicant stated that the "tubing and secondary internals in the replacement steam generators are not susceptible to corrosion due to advanced material design."

Thermally treated Alloy 690 may be susceptible to corrosion as demonstrated in laboratory tests, but are more resistant than Alloy 600 mill annealed which was previously used in the DCPP steam generators. Please clarify the statement in the LRA regarding the corrosion susceptibility of the Alloy 690 material in the replacement steam generators.

PG&E Response to RAI B2.1.8-1

LRA Section B2.1.8, Operating Experience section, has been revised to indicate the tubing and secondary internals in the replacement steam generators are more resistant to corrosion due to advanced material design. See revised LRA Section B2.1.8 in Enclosure 2.

RAI B2.1.10-1

10 CFR Part 54.4(a) provides the regulations for which plant systems, structures, and components are within the scope of the license renewal. These include items under 10 CFR 54.4(a)(2), which are all nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in safety-related systems. The "parameters monitored or inspected" program element of the Closed-Cycle Cooling Water AMP in the GALL Report, Section XI.M21, indicates that the program includes monitoring the effects of corrosion and stress corrosion cracking by testing and inspection in accordance with the guidance in the EPRI report closed cooling water chemistry guideline as well as performance testing for pumps and heat exchangers.

LRA, Appendix B, Section B2.1.10 indicates that the applicant's Closed-Cycle Cooling Water Program will be consistent with the GALL Report Section XI.M21 with various exceptions. In both the LRA B2.1.10 program description and the applicant's basis document, the applicant indicated that the program will not conduct inspections or performance testing for components in scope of license renewal under criterion of 10 CFR 54.4(a)(2). It is not clear to the staff what the technical basis is for limiting the prescribed guidance in the GALL Report based on how a component was scoped into the license renewal process.

Provide justification for not performing the program's inspections and performance testing on components within the scope of license renewal under criterion 10 CFR 54.4(a)(2).

PG&E Response to RAI B2.1.10-1

PG&E will monitor the corrosion of closed cooling water components by inspecting the condition of corrosion coupons installed in the system and perform internal inspections of select components within the systems. These methods will verify that wetted material exposed to the chemistry of the closed cooling water systems are not experiencing corrosion. The corrosion coupons are strips of metal (i.e. copper, carbon steel, stainless steel, etc) that are installed in the closed cooling water systems in a manner such that they are exposed to the cooling water. Periodically these coupons are removed and their condition can be evaluated. This inspection will provide DCPP indication if significant corrosion is occurring in the system. The material of these corrosion coupons is representative of most of the materials that are used in the system. For those components that do not have material represented by the corrosion coupons, internal inspections will be performed on those components, or other component with similar material, in order to monitor for corrosion. See revised LRA Section B2.1.10 and Table A4-1 in Enclosure 2.

RAI B2.1.10-2

The Closed-Cycle Cooling Water System AMP in the GALL Report, Section XI.M21, includes non-chemistry monitoring parameters, including pump and heat exchanger performance monitoring.

LRA, Appendix A, Section A1.10 indicates that the Closed-Cycle Cooling Water System Program will include maintenance of system chemistry parameters, but does not mention any non-chemistry monitoring parameters.

Update the Final Safety Analysis Report (FSAR) supplement to be consistent with LRA Section B2.1.10 program description, including monitoring of non-chemistry parameters or provide justification for not including the monitoring of these parameters.

PG&E Response to RAI B2.1.10-2

LRA Appendix A, Section A1.10 has been revised to address monitoring of non-chemistry parameters. See revised LRA Section A1.10 in Enclosure 2.

RAI B2.1.16-1

GALL Report AMP XI.M32, "One-Time Inspection," "detection of aging effects" program element states that "the inspection includes a representative sample of the system population, and, where practical, focuses on the bounding or lead components most susceptible to aging…." The applicant's One-Time Inspection program description states, in part, that sampling will be conducted "using an engineered sampling technique for each material-environment group based on criteria such as the longest service period, most severe operating conditions, lowest design margins, lowest or stagnant flow conditions, high flow conditions, and highest temperature."

Provide additional details of the sampling procedure to be used. Indicate whether the One-Time Inspection program utilizes a risk-informed inservice inspection or similar methodology, or an alternative form of probabilistic or statistical sampling to select the number, types, and locations of the components to be inspected under this program. If not, provide additional details of the sampling procedure to be used.

PG&E Response to RAI B2.1.16-1

The DCPP One-time Inspection (OTI) Program uses a risk-informed methodology by identifying the material/environment combination most susceptible to the aging mechanisms of concern. Inspection sample sizes will be determined based on an assessment of materials of fabrication, environment, plausible aging effects and mechanisms, and operating experience. The OTI program determines NDE sample size for each material-environment group using an engineered sampling technique for each material-environment group based on criteria such as the longest service period, most severe operating conditions, lowest design margins, lowest or stagnant flow conditions, high flow conditions, and highest temperature. Component selection will be performed by the system engineer or other knowledgeable personnel. A representative sample is selected at locations in the system that has stagnant or low flow conditions where the full benefit of a water chemistry program may not be realized.

Loss of Material -
System components containing carbon steel managed by Water Chemistry Programs were selected over other material types as carbon steel has the lowest corrosion resistance. In the case where carbon steel is not present, such as stainless steel primary systems exposed to borated water, no OTI inspections were identified for material loss. However, volumetric examinations for the detection of stress corrosion cracking as required by OTI Program and the OTI of Class-1 Small Bore Program provide additional opportunities to inspect for loss of material for stainless steel in borated water.

Total Sample = 15

System components containing carbon steel managed by the Fuel Oil Chemistry Program were selected over other material types as carbon steel has the lowest corrosion resistance than other material types. Locations of low flow or stagnant conditions were selected where water / contaminants may collect over time.

Total Sample = 8

System components containing carbon steel and copper alloys managed by the Lubrication Oil Chemistry Program were selected over other material types as carbon steel and copper alloys have lower corrosion resistance than other material types in this environment. Locations of low flow or stagnant conditions were selected where water / contaminants may collect over time.

Total Sample = 5

Cracking -
System components containing stainless steel greater than 140°F managed by the Water Chemistry Program in stagnant or low flow locations were selected for examination. Examinations performed as part of OTI of Class-1 Small Bore Program may supplement these inspections if the service temperature is greater than 140°F.

Total Sample = 2

Fouling-
System components containing heat exchangers managed by the Water Chemistry Program were selected based on environment (Borated Water and Auxiliary Feed Water).

Total = 2

System components containing heat exchangers managed by the Lubricating Chemistry Program were selected to provide a representative sample. Heat exchangers selected have oil flow only when the associated pump runs which is infrequent.

Total = 3

RAI B2.1.16-2

LRA Table 3.3.1, Item 3.3.1.07 refers to the aging evaluation of stainless steel non-regenerative heat exchanger components exposed to treated borated water in the auxiliary systems. The aging effect identified is cracking due to stress corrosion cracking, and the GALL Report recommends the use of the Water Chemistry Program to manage this effect. The GALL Report also states that further evaluation is recommended and that an acceptable verification program is to include temperature and radioactivity monitoring of the shell side water, and eddy current testing of the tubes. The applicant proposes to manage this aging effect using its Water Chemistry Program, with its One-Time Inspection Program to be used for verification of program effectiveness.

In its further evaluation of this aging effect, the applicant states that temperature and radioactivity of the shell-side water of the letdown (non-regenerative) heat exchanger is monitored continuously by installed plant instrumentation. The applicant also states that its One-Time Inspection Program will be used in lieu of eddy-current testing of the tubes to provide confirmation that cracking is not occurring. However, the applicant does not identify the testing technique to be used to perform the proposed inspections.

Describe the details of the inspection technique to be used to perform the one-time inspection of these components in lieu of eddy-current testing and provide relevant plant or industry experience to demonstrate the effectiveness and reliability of this technique.

PG&E Response to RAI B2.1.16-2

The Water Chemistry Program manages crack initiation and growth of SCC in the non-regenerative heat exchangers and seal water heat exchangers. The One-Time Inspection (OTI) Program verifies the effectiveness of the Water Chemistry Program in preventing cracking due to SCC for in-scope components. If selected as part of the inspection sample, the OTI program will perform eddy current testing on the heat exchangers.

RAI B2.1.17-1

Program element "parameters monitored or inspected" of GALL Report Program XI.M33, "Selective Leaching of Materials" states:

> *The visual inspection and hardness measurement is to be a one-time inspection. Because selective leaching is a slow acting corrosion process, this measurement is performed just before the beginning of the license renewal period. Follow-up of unacceptable inspection findings includes expansion of the inspection sample size and location.*

In the LRA, the applicant describes its Selective Leaching of Materials Program in Appendix B2.1.17 as consistent with the GALL Report, with no exceptions or enhancements. The program descriptions provided in the LRA and the FSAR Supplement (A.1.17) state that the detection of selective leaching will result in the performance of an engineering evaluation, which will then determine the need for an expansion of inspection sample sizes and locations. It is unclear if an engineering evaluation will result in an expansion of inspection sample sizes and locations, consistent with the GALL Report.

Clarify if the Selective Leaching of Materials Program will expand the inspection sample size and location if selective leaching is detected. Provide justification if no expansion of sample size and location is to occur if selective leaching is detected.

PG&E Response to RAI B2.1.17-1

LRA Sections A1.17 and B2.1.17 have been revised to clarify that if evidence of selective leaching is discovered in the implementation of the program, an engineering evaluation will determine the extent of expansion of the sample size and locations for additional inspections and evaluations. See revised LRA Sections A1.17 and B2.1.17 in Enclosure 2.

RAI B2.1.19-1

GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping," states that a volumetric inspection should be used to detect cracking in small-bore piping. However, the applicant's One-Time Inspection of ASME Code Class 1 Small-Bore Program in LRA Section B2.1.19 states that a reliable and effective volumetric inspection technique to detect cracking in socket welds is currently not available. The applicant instead proposes to use the visual examination technique (VT-2) for the examination of small-bore socket welds.

The applicant's proposed usage of the VT-2 technique for the examination of these welds conflicts with the guidance in the GALL Report.

Justify the proposed deviation from the GALL Report recommendation to perform volumetric examinations of socket welds in ASME Code Class 1 small-bore piping.

PG&E Response to RAI B2.1.19-1

DCPP has 47 small-bore piping socket welds identified as high risk (both units); high risk Category-2. Category-2 as defined in EPRI report TR-112657, Rev B-A, "Revised Risk-Informed Inservice Inspection Evaluation Report" are those components that have a high consequence and medium failure potential. Out of this population 13 small-bore piping socket welds are selected for surface examination during the interval. ASME Code Edition 2001 with 2003 Addenda, Section XI, Table IWB requires a surface examination of the selected socket welds.

LRA Section B2.1.19 has been revised to address volumetric examination and sample size and to clarify plant operating experience. See revised LRA Section B2.1.19 in Enclosure 2.

RAI B2.1.19-2

GALL AMP XI.M35 states that the One-Time Inspection of ASME Class 1 Small-Bore Piping Program is applicable only to plants that have not experienced cracking of ASME Class 1 small-bore piping. It further states that "[s]hould evidence of significant aging be revealed by a one-time inspection or previous operating experience, periodic inspection will be proposed, as managed by a plant specific program."

During a review of the applicant's operating experience, the staff noted that there have been failures of Class 1 small bore piping at DCPP.

In view of the above-cited GALL Report guidance and plant-specific operating experience, justify the proposed application of the applicant's proposed One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program, or provide a plant-specific AMP for managing aging during the period of extended operation.

PG&E Response to RAI B2.1.19-2

NUREG-1801, Revision 1, Volume 2, states within the Program Description of XI.M35 that OTIs provide "...additional assurance that either aging of small-bore ASME Code Class 1 piping is not occurring or the aging is insignificant, such that an aging management program (AMP) is not warranted." DCPP has had one occurrence of stress corrosion cracking in Class-1 small bore piping during plant operation and one occurrence of stress corrosion cracking in Class-2 small bore piping. The Class-1 event occurred on a segment of piping configured in a manner that increased the base metals to SCC compared to the remaining population of Class-1 small bore piping. The close proximity of the two weld toes, 0.125 inches apart, allowed the pipe material to become overly sensitized during the welding process. The corrective action replaced the piping material with a stabilized grade of stainless steel to address the material sensitization and reduce the susceptibility of the heat affected zones to stress corrosion cracking. The occurrence of SCC in Class-2 small bore piping with a configuration that allowed it to become overly sensitized during the welding process. The corrective actions for the Class-2 piping involved a design change to increase the spacing between the welds.

Based on the unique piping configuration and the limited frequency of cracking (one Class-1 occurrence in 50 plant-operating years), the aging that has occurred is considered insignificant and does not warrant periodic inspection beyond inspections already specified by ASME Section XI. If OTIs of Class-1 small bore piping identify additional SCCs, then a new periodic plant specific AMP would be implemented.

RAI B2.1.22-1

GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," states that the program includes visual inspections of internal surfaces of steel piping, piping components, ducting, and components in an internal environment (such as indoor uncontrolled air, condensation, and steam) for degradation from various corrosion mechanisms. In the two exceptions to the GALL Report stated in LRA Section B2.1.22, the program is expanded to include additional materials (aluminum, asbestos cement, copper alloy, elastomers, nickel alloys, stainless steel, and cast austenitic stainless steel) and to include additional examination techniques (volumetric testing and physical manipulation).

In the actual application of this AMP as summarized in the applicant's LRA, the scope of the program is significantly expanded beyond both GALL XI.M38 and the applicant's description of the program in LRA Appendix B, Section B2.1.22. This expanded application of the program in the LRA appears to encompass a substantial number of additional component types, materials, and environments beyond those in the GALL Report and the applicant's AMP description.

Clarify that the program description for Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program in Appendix B of the LRA encompasses the actual application of the program as described in the LRA.

PG&E Response to RAI B2.1.22-1

LRA Section B2.1.22 states that the "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" aging management program (AMP) will manage the aging of the internal surfaces of piping, piping components, ducting and other components that are not within the scope of other aging management programs consistent with NUREG-1801, Chapter XI.M38, Element 1. Component types, materials, and environments managed by this program are as follows.

Component:

Type	Explanation of Component Type
Abandoned-in-place components	Note 1
Flexible hoses	Note 2
Bellows	Note 4
Compressor	Note 4
Fan	Note 3
Filter	Note 4
Lubricator	Note 4
Regulators	Note 4
Silencer	Note 4
Turbine	Note 4
Sensor element	Note 4
Sight gauge	Note 2
Strainer	Note 2
Demineralizer	Note 2
Pumps	Note 2
Vessel	Note 4
Switch	Note 2

Note 1: The aging of internal surfaces of abandoned-in-place components is not managed by other programs of sampling and verification of other special-environment programs and therefore are among the "internal surfaces … that are not included in other aging management programs for loss of material" as stated in NUREG-1801, Chapter XI.M38, Element 1.

Note 2: With respect to component types of flexible hoses, sight gauge, strainer, demineralizer pump (casing – bowl) and switch (the component can be also characterized as a multi-port valve), these components are included in the definition of the term "piping and piping components" in NUREG-1801, Chapter IX.B.

Note 3: With respect to the component type fan, this component is included in the definition of the term "ducting and components" in NUREG-1801, Chapter IX.

Note 4: With respect to component types bellows, compressor, fan, filter, lubricator, regulators, silencer, turbine, sensor element and vessel, these component types are considered as among the "other components" having internal surfaces whose aging is not managed by other aging management programs as stated in NUREG-1801, Chapter XI.M38, Element 1.

Materials:

NUREG-1801, Chapter IX.C defines as “steel” a list of materials that it characterizes as “vulnerable to general, pitting and crevice corrosion, even though the rates of aging may vary” and states that these “metal types are generally grouped for AMRs under the broad term ‘steel’ .“ Included in the definition of NUREG-1801, Chapter IX.C for steel is galvanized steel and malleable iron, which is an alternative name for ductile iron. NUREG-1801 Chapter IX.C states that the broad purpose of the definition of copper alloy (greater than 15 percent zinc) is “to collect those copper alloys whose critical alloying elements are above certain thresholds that make the alloy susceptible to stress corrosion cracking, selective leaching (except for inhibited brass), and pitting and crevice corrosion.” Included explicitly is aluminum bronze greater than eight percent aluminum. The XI.M38 aging management program includes galvanized steel, ductile iron and copper alloy (greater than 8 percent aluminum) consistent with NUREG-1801, Chapter IX.C.

Environments:

Treated Borated Water - Although treated borated water is an environment addressed in NUREG-1801, Chapters VII and IX; NUREG-1801, Chapter XI does not provide a specific aging management program to address elastomers exposed to the treated borated water environment. Elastomers exposed to the treated borated water are among the “internal surfaces … that are not included in other aging management programs for loss of material” as stated in NUREG-1801, Chapter XI.M38, Element 1. LRA Table 3.3.1, Item Number 3.3.1.12 describes the application of the "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" aging management program in this environment.

Raw Water – The definition of “raw water” in NUREG-1801, Chapter IX.D includes raw, untreated fresh, salt and ground water. Floor drains and reactor buildings and auxiliary building sumps may be exposed to a variety of untreated water that is thus classified as raw water, for the determination of aging effects. Raw water may contain contaminants, including oil and boric acid, depending on the location, as well as originally treated that is not monitored by a chemistry program. The contents of floor drains, sumps and waste streams are among the “internal surfaces … that are not included in other aging management programs for loss of material” as stated in NUREG-1801, Chapter XI.M38, Element 1. LRA Table 3.3.1, Item Numbers 3.3.1.76, 3.3.1.78, 3.3.1.79, and 3.3.1.81, and Table 3.4.1, Item Numbers 3.4.1.16 and 3.4.1.32 further describe the application of the "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" aging management program in this environment.

Potable Water – Potable water is an internal environment for in-scope components of the Makeup Water System 16 and the HVAC System 23. The potable water environment is further described in LRA Table 3.0-1. NUREG-1801 does not address the potable water environment and therefore these surfaces are among the “internal surfaces … that are not included in other aging management programs for loss of material” as stated in NUREG-1801, Chapter XI.M38, Element 1.

Sulfuric Acid – Sulfuric acid is an internal environment for in-scope components of the Turbine Steam Supply System 04 and the Makeup Water System 16. The sulfuric acid environment is further described in LRA Table 3.0-1. NUREG-1801 does not address the sulfuric acid environment and therefore these surfaces are among the “internal surfaces … that are not included in other aging management programs for loss of material” as stated in NUREG-1801, Chapter XI.M38 Element 1.

Diesel Exhaust – Although diesel exhaust is an environment addressed in NUREG-1801, Chapters VII and IX; NUREG-1801, Chapter XI does not provide a specific aging management program to address the diesel exhaust environment and therefore these surfaces are among the “internal surfaces … that are not included in other aging management programs for loss of material” as stated in NUREG-1801, Chapter XI.M38, Element 1. LRA Table 3.3.1, Item Numbers 3.3.1.06 and 3.3.1.18 further describe the application of the "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" aging management program in this environment.

Lubricating Oil – The Lubricating Oil Analysis aging management program B2.1.23 is credited for managing the internal surfaces of in-service components exposed to lubricating oil with the exception of the surfaces of abandoned-in-place components. The aging of internal surfaces of abandoned-in-place components is among the “internal surfaces … that are not included in other aging management programs for loss of material” as stated in NUREG-1801, Chapter XI.M38, Element 1. LRA Table 3.4.1, Item Numbers 3.4.1.07 and 3.4.1.18 further describe the application of the "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" aging management program in this environment.

Fuel Oil – The Fuel Oil Chemistry aging management program B2.1.14 is credited for managing the internal surfaces of in-scope components exposed to fuel oil. The internal surfaces of abandoned-in-place components are among the “internal surfaces … that are not included in other aging management programs for loss of material” as stated in NUREG-1801, Chapter XI.M38, Element 1. LRA Table 3.3.1, Item Numbers 3.3.1.20 and 3.3.1.32 further describe the application of the "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" aging management program in this environment.

RAI B2.1.22-2

In LRA Appendix B, Section B2.1.22, the applicant states that this program "will use the work control process for preventive maintenance and surveillance to conduct and document inspections."

The term "work control process" appears nowhere else in the applicant's LRA except in the Appendix A FSAR supplement for this AMP, nor does it appear anywhere in either the GALL Report or NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." Consequently, the staff is unable to determine precisely what is meant by this term in the context of the applicant's program description.

Define what is meant by the term "work control process" as it is used in the description of the program, particularly with respect to what program elements in the GALL Report it impacts and how it impacts these elements.

PG&E Response to RAI B2.1.22-2

NUREG 1801, Rev-1, XI.M38 (B2.1.22) "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components", Element-3 states "Visual inspections of internal surfaces of plant components are performed during maintenance or surveillance activities". Appendix B states that the work control process will be utilized to identify those preventative maintenance activities and surveillance to conduct and document inspections. The DCPP work control process generates the corrective maintenance, preventative maintenance, and surveillance work orders (SAP Order/Operations) which direct the maintenance department during the performance of maintenance activities. The SAP system provides a recurring task scheduler to track completion and future due dates for all preventive maintenance and surveillance test activities. During the generation of maintenance work orders for in-scope components requiring aging management the DCPP work control process will be used to identify those maintenance activities that would provide opportunistic visual inspection of accessible internal surfaces.

RAI B2.1.24-1

The GALL Report AMP XI.E1 program description states that cables and connections from accessible areas (the inspection sample) are inspected and represent, with reasonable assurance, all cables and connections in the adverse localized environments. The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program in the LRA states "At least once every 10 years, accessible cables/cable jackets, connections, and terminal blocks within the scope of license renewal located in an adverse localized environment are inspected."

It is unclear if the applicant will use sampling or include all cables (within the scope of license renewal) in its inspection.

Please clarify if all accessible cables and connections within adverse localized environments will be inspected consistent with the GALL Report.

PG&E Response to RAI B2.1.24-1

The GALL Report AMP XI.E1 program requires that a representative sample of accessible in scope electrical cables and connections installed in adverse localized environments be visually inspected for cable jacket and connection surface anomalies.

Rather than performing an inspection of a representative sample of in-scope cables and connections PG&E will inspect all accessible cables, connections and terminal blocks that are identified within adverse localized environments.

RAI B2.1.25-1

In order for NRC staff to review an AMP with enhancement(s), the impact of the enhancement(s) for each element of the AMP must be clearly stated.

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program (LRA Appendix B, Section B2.1.25) states "the following enhancement will be implemented in the following program elements: Scope of Program - Element 1, Parameters Monitored/Inspected - Element 3, Detection of Aging Effects - Element 4, Acceptance Criteria - Element 6, and Corrective Actions - Element 7." The LRA lacks detailed information on how the enhancement impacts each element. This information is also incomplete in the basis document.

Explain how each element will be impacted by enhancement such that it will be consistent with the GALL Report.

PG&E Response to RAI B2.1.25-1

Prior to the period of extended operation, plant procedures will be developed or revised in the following program elements as discussed below:

Scope of Program - Element 1

Plant procedures will be developed or revised to specify the cables and connections used in circuits with sensitive, high voltage, low-level signal instrumentation circuits within the scope of this program.

Parameters Monitored/Inspected - Element 3

Calibration surveillance tests are used to manage the aging of the cable insulation and connections for in scope radiation monitors so that circuits perform their intended functions. Cable testing is used to manage the aging of the cable insulation for the Nuclear Instrumentation System. Cable tests such as insulation resistance testing or other tests are performed for detecting deterioration of the cable insulation system. Procedures associated with calibration and testing will be developed or revised to note the parameters that require monitoring for indications of age related degradation.

Detection of Aging Effects - Element 4

The cables and connections for in-scope high voltage, low level signal circuits are subjected to calibration or cable testing. These calibrations or cable tests provide reasonable assurance that severe aging degradation will be detected prior to loss of the cable and connector intended function. Calibration and test procedures will be developed or revised to ensure that all calibration and surveillance results that fail to

meet acceptance criteria will be reviewed, including consideration of cable aging effects, as appropriate, and that corrective actions are taken. Additionally procedures will be in place to ensure that a review of the calibration and test results will be completed prior to the period of extended operation and every 10 years thereafter.

Acceptance Criteria - Element 6

Plant procedures will be developed or revised to establish cable testing acceptance criteria based on the type of cable and type of test performed.

Corrective Actions - Element 7

Plant procedures will be developed or revised to ensure that when test or calibration acceptance criteria are not met, a corrective action document is initiated and an engineering evaluation is performed. The evaluation will consider the significance of the test results, the operability of the component, the reportability of the event, the extent of the concern, the potential root causes for not meeting the acceptance criteria, the corrective actions required, and likelihood of recurrence to ensure that the intended functions of the electrical cable system can be maintained consistent with the current licensing basis.

RAI B2.1.36-1

The applicant proposed to credit the Metal Enclosed Bus program for inspecting the in-scope iso-phase bus. The iso-phase bus provides the station blackout delay access offsite power source through back feeding the unit transformers and is included in the scope of the Metal Enclosed Bus Program. However, the inspection aspects of the iso-phase bus are different from those of the non-segregated bus. For example, the iso-phase bus does not have bus insulation, but has a bare conductor tube with no insulation material. Therefore, the bus insulation inspection as describe in the Metal Enclosed Bus Program is not applicable.

The GALL Report XI.E4 program is written specifically for managing non-segregated buses. The program attributes including parameters monitored or inspected, detection of aging effects, and acceptance criteria for non-segregated buses may not be appropriate for the iso-phase bus.

Explain how the inspections of non-segregated bus as described in the Metal Enclosed Bus Program are appropriate for the iso-phase bus.

PG&E Response to RAI B2.1.36-1

The scope of metal enclosed bus program includes both non-segregated phase bus sections and isolated phase bus sections that are included within the scope of license renewal due to being part of the station blackout recovery path.

The basic design of the non-segregated and Isophase busses is similar. Both designs include conducting bus bar on rigid insulated supports routed in a metal enclosure.

Some inspection parameters described in GALL for Metal Enclosed Bus would not be applicable to Isophase bus. The bus segments are not wrapped with insulation, as is the non-segregated bus. Therefore, inspection of insulation is not applicable. Most of the Isophase bus sections are welded together. There are three locations of bolted connections within the Isophase bus. These connections are inspected as part of Metal Enclosed Bus program, LRA Section B2.1.36. PG&E manages bolted connections at the ends of the isolated phase bus under the maintenance programs of the motor operated disconnect, the main unit transformers, and the auxiliary transformers. The bolted connections that are part of active components are not within the scope of this aging management program.

LRA Sections 2.5, 2.5.1.6, A1.36, B2.1.36, and Table 3.6.2-1 have been revised to account for the differences between the isolated phase and non-segregated phase bus designs. Section B2.1.36, the Metal Enclosed bus aging management program, is revised to take an exception that the isolated phase bus inspections do not require inspection or testing of bolted connections between bus segments or the inspection of insulating materials on the bus. See revised LRA Sections 2.5, 2.5.1.6, A1.36, and B2.1.36, and Table 3.6.2-1 in Enclosure 2.

LRA Amendment 2

LRA Section	RAI
Section 2.5	B2.1.36-1
Section 2.5.1.6	B2.1.36-1
Section A1.10	B2.1.10-2
Section A1.17	B2.1.17-1
Section A1.36	B2.1.36-1
Section B2.1.1	B2.1.1-1
Section B2.1.3	B2.1.3-2
Section B2.1.8	B2.1.8-1
Section B2.1.10	B2.1.10-1
Section B2.1.17	B2.1.17-1
Section B2.1.19	B2.1.19-1
Section B2.1.36	B2.1.36-1
Table 3.6.2-1	B2.1.36-1
Table A4-1	B2.1.10-1

2.5 SCOPING AND SCREENING RESULTS: ELECTRICAL AND INSTRUMENTATION AND CONTROL SYSTEMS

The scoping and screening results for electrical and instrument and control system components consist of a list (Table 2.5-1, Electrical and I&C Component Groups Requiring Aging Management Review) of component types that require AMR.

Using the plant "spaces" approach, all electrical and instrument and control components were reviewed as a group regardless of the system assigned to each component. Bounding environmental conditions were used to evaluate the identified aging effect(s) with respect to component function(s) to determine the passive component groups that require AMR. This methodology is discussed in Section 2.1.3.3 and is consistent with the guidance in NEI 95-10.

The interface of electrical and instrument and control components with other types of components and the assessments of these interfacing components are provided in the appropriate mechanical or structural sections. The evaluation of electrical racks, panels, frames, cabinets, cable trays, conduit, manhole, duct banks, transmission towers and their supports is provided in the structural assessment documented in Section 2.4.

The following electrical component groups were evaluated to determine the groups that require AMR:

- Cable Connections (metallic parts)
- Connectors (exposed to borated water)
- Fuse Holders (not part of a larger assembly)
- High Voltage Insulators
- Insulated Cable and Connections (includes the following):
    - Electrical cables and connections not subject to 10 CFR 50.49 EQ requirements
    - Electrical cables and connections used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation resistance
    - Inaccessible Medium-Voltage Electrical Cables not subject to 10 CFR 50.49 EQ requirements

- Metal Enclosed Bus (includes the following):
  - Non-segregated Phase Bus
    - Bus bar and connections
    - Bus enclosure
    - Bus Insulation and insulators
  - Isolated Phase Bus
    - Bus bar
    - Bus enclosure
    - Bus insulators
- Switchyard Bus and Connections
- Terminal Blocks (not part of a larger assembly)
- Transmission Conductors and Connections
- Lightning Rods
- Electrical equipment subject to 10 CFR 50.49 environmental qualification (EQ) requirements
- Penetrations, Electrical
- Grounding conductors
- Cable Tie Wraps

A license renewal boundary drawing (LR-DCPP-ELEC-502110) was created from the plant one-line diagram. The plant one-line diagram schematically shows the portions of the plant AC electrical distribution system, including the SBO recovery path, that are included within the scope of license renewal.

2.5.1.6 Metal Enclosed Bus

Metal Enclosed Bus is bus that is enclosed and not part of an active component such as switchgear, load centers or motor control centers. There are typically three types of metal enclosed bus:

- Isolated Phase Bus
- Non-Segregated Phase Bus
- Segregated Phase Bus

The in-scope non-segregated phase bus supports the restoration of offsite power to meet the SBO requirements is in the scope of license renewal. The non-segregated phase bus consists of the following component types:

- Bus bar and connections
- Bus enclosure
- Bus Insulation and insulators

The in-scope isolated phase bus supports the restoration of offsite power to meet the SBO requirements is in the scope of license renewal. The isolated phase bus consists of the following component types:

- Bus bar and connections
- Bus enclosure
- Bus insulators

The function of the non-segregated phase bus, the isolated phase bus and bus bar and connections is to maintain electrical continuity between specified sections of an electrical circuit to deliver voltage and current.

The function of the bus enclosure is to provide for expansion (non-segregated and isolated phase bus) and separation of the bus (non-segregated) as well as structural support (non-segregated and isolated phase bus). The function of the bus insulation serves to electrically insulate the non-segregated phase bus bars from each other and the enclosure. The function of the bus insulators is to support and electrically insulate the non-segregated and isolated phase bus bars from the enclosure.

DCPP does not use segregated phase bus.

Deleted: and isolated phase bus

Deleted: following component types are part of the

Deleted: and isolated phase bus

Deleted: and insulators is

Deleted: and supports

A1.10 CLOSED-CYCLE COOLING WATER SYSTEM

The Closed-Cycle Cooling Water System program manages loss of material, cracking, and reduction in heat transfer for components within the scope of license renewal in closed-cycle cooling water systems. The program includes maintenance of system chemistry parameters following the guidance of EPRI TR 107396, Revision 1, *Closed Cooling Water Chemistry Guidelines (EPRI 1007820)* to minimize aging. The program provides for: (1) preventive measures to minimize corrosion including maintenance of corrosion inhibitor, pH buffering agent, and biocide concentrations, and (2) periodic system and component performance testing and inspection. Periodic inspection and testing to confirm function and monitor corrosion is performed in accordance with EPRI TR 107396, Revision 1 (EPRI 1007820), and industry and plant operating experience.

A1.17 Selective Leaching of Materials

The Selective Leaching of Materials program manages the loss of material due to selective leaching for brass (copper alloy >15 percent zinc), aluminum-bronze (copper alloy >8 percent aluminum), and gray cast iron components within the scope of license renewal that are exposed to raw water, including condensation, and treated water.

The Selective Leaching of Materials program includes a one-time visual inspection and hardness measurement (where feasible based on form and configuration) or other industry-accepted mechanical inspection techniques of selected components that may be susceptible to selective leaching to determine whether loss of material due to selective leaching is occurring, and whether the process will affect the ability of the components to perform their intended functions for the period of extended operation. If evidence of selective leaching is discovered in the implementation of the program, an engineering evaluation will determine the extent of expansion of the sample size and locations for additional inspections and evaluations. Follow up examinations or evaluations will be performed as required to ensure component functionality during the period of extended operation.

The Selective Leaching of Materials program is a new program and the inspections will be completed within the 10-year period prior to the period of extended operation.

A1.36 Metal enclosed Bus

The Diablo Canyon metal enclosed bus program manages aging of in-scope non-segregated phase and isolated phase bus.

The non-segregated phase portion of the program manages the effects of loose connections, embrittlement, cracking, melting, swelling, or discoloration of insulation, loss of material of bus enclosure assemblies, hardening of boots and gaskets, and cracking of internal bus supports to ensure that non-segregated phase metal enclosed buses within the scope of license renewal are capable of performing their intended function.

Prior to the period of extended operation and every 10 years thereafter, internal portions portions of the in-scope non-segregated phase MEBs are visually inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus insulation is inspected for signs of embrittlement, cracking, melting, swelling, hardening or discoloration, which may indicate over heating or aging degradation. The internal bus supports are inspected for structural integrity and signs of cracks. The bus enclosure assemblies are inspected for loss of material due to corrosion and hardening of boots and gaskets.

Prior to the period of extended operation and every 10 years thereafter, a sample of the accessible bolted connections of non-segregated phase internal bus work is checked for for loose connections by measuring connection resistance or thermography. Where the alternative visual inspection is used to check bolted connections, the first inspection will be completed prior to the period of extended operation and every five years thereafter.

When contact resistance test or thermography is not performed on non-segregated phase bus, a visual inspection of connection insulation material to detect surface anomalies, such as discoloration, cracking, chipping or surface contamination will be performed. The first visual inspection for license renewal will be performed prior to the period of extended operation and once every five years thereafter.

The isolated phase portion of the program manages the effects of cracking and loss of material of bus enclosure assemblies, hardening of gaskets, and cracking of internal bus supports to ensure that isolated phase metal enclosed buses within the scope of license renewal are capable of performing their intended function.

Deleted: Metal Enclosed Bus

Deleted: ,

Deleted: t

Deleted: , and t

Deleted: on the

Prior to the period of extended operation and every 10 years thereafter, internal portions portions of the in scope isolated phase MEBs are visually inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The internal bus supports are inspected for structural integrity and signs of cracks. The bus enclosure assemblies are inspected for loss of material due to corrosion and hardening of boots and gaskets.

B2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Program Description

ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program inspections are performed to manage cracking, loss of fracture toughness, and loss of material in Class 1, 2, and 3 piping and components within the scope of license renewal. The program includes periodic visual, surface, volumetric examinations and leakage tests of Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting. These components are identified in ASME Section XI Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 for Class 1, 2 and 3 components, respectively. DCPP inspections meet ASME Section XI requirements. The DCPP ISI Program is in accordance with 10 CFR 50.55a and ASME Section XI, 2001 edition through 2003 addenda. In conformance with 10 CFR 50.55a(g)(4)(ii), the DCPP ISI Program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified 12 months before the start of the inspection interval.

The ASME Section XI, IWB, IWC, and IWD Inservice Inspection program is implemented by plant procedures. DCPP is in the third 10-year interval which will end on May 7, 2015 for Unit 1, and March 13, 2016 for Unit 2. DCPP is following Inspection Program B as allowed by the ASME Code. Requirements are included for scheduling of examinations and tests for Class 1, 2, and 3 components. The program requires periodic visual, surface, volumetric examinations and leakage tests of all Class 1, 2 and 3 pressure-retaining components. The DCPP ASME Section XI ISI program provides measures for monitoring to detect aging effects prior to loss of intended function and provides measures for repair and replacement of Class 1, 2, and 3 piping and components in accordance with the requirements of IWA-4000.

ISI of reactor vessel flange stud holes, closure studs, nuts, washers, and bushings are evaluated in the Reactor Head Closure Studs program (B2.1.3).

ISI of Class 1, 2, and 3 component supports are evaluated in the ASME Section XI, Subsection IWF program (B2.1.29).

The DCPP ASME Class 1, 2, and 3 components described in Subsections IWB-1220, IWC-1220, and IWD-1220 are exempt from the volumetric and surface examination requirements of Subsections IWB-2500, IWC-2500, and IWD-2500.

The ISI program is a monitoring program that provides measures for detecting the aging effects prior to loss of intended function, but does not prevent degradation due to aging effects.

The ISI Program uses visual, surface and volumetric examinations conducted in accordance with approved DCPP procedures that meet ASME Section XI requirements. Examinations are conducted by personnel qualified and certified in accordance with ASME Code requirements in Section XI IWA-2300. The NDE techniques used to inspect Class 1 (Table IWB-2500-1), Class 2 (Table IWC-2500-1), and Class 3 (Table IWD-2500-1) components are consistent with the ASME Section XI Code for the components.

The ISI Program, Subsections IWB, IWC, and IWD, is credited for detection of loss of fracture toughness aging effects in cast austenitic stainless steel piping, valves, and reactor coolant pump casings.

The ISI component examination schedules implemented in the DCPP ISI Program are consistent with the requirements of ASME Section XI, IWB-2412, IWC-2412, and IWD-2412 for Inspection Program B. Flaw indications and relevant conditions that have been been evaluated and determined to be acceptable for continued service are re-examined during subsequent inspection periods. Examinations that reveal flaw indications and relevant conditions that have been evaluated and exceed the acceptance standards are extended to include additional examinations in accordance with IWB-2430, IWC-2430, or or IWD-2430.

Indications, relevant conditions, and resolution of rejectable indications and relevant conditions are evaluated as required by ASME Section XI IWB-3000, IWC-3000, and IWD-3000. DCPP evaluates every indication. Examination results are evaluated in accordance with IWB-3100, IWC-3100, or IWD-3100 by comparing the results with acceptance standards of IWB-3400, JWB-3500, IWC-3400, and IWC-3500, or IWD-3400 3400 and IWD-3500 for Class 1, Class 2, or Class 3 components, respectively. Flaws exceeding the size of allowable flaws, as defined in IWB-3500, IWC-3500, or IWD-3500 are evaluated using the analytical procedures of IWB-3600, IWC-3600, or IWD-3600, respectively.

Deleted: F

Deleted: or

Deleted: and

Deleted: or

Deleted:

Deleted: or

Deleted: and

Deleted: or

Deleted: may be

Deleted: or

NUREG-1801 Consistency

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is an existing program that is consistent with NUREG-1801, Section XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

DCPP operating experience is evaluated and corrective actions are implemented to ensure that program operability is maintained. This is accomplished by promptly identifying and documenting any condition that indicates degradation of the systems that fall under the DCPP ISI Program, using the Corrective Action Program. Industry operating experience evaluations and ISI component inspections and testing results have proven that the effects of aging are adequately being managed so that the intended functions are maintained consistent with the current licensing basis for the period of extended operation

DCPP is now beginning the third 10-year interval of applying the requirements of ASME Section XI in its ISI Program to manage aging effects in Class 1, 2, and 3 components and their integral attachments in light-water cooled power plants. DCPP Inspections meet ASME Section XI requirements and can manage aging such as cracking, loss of material and loss of fracture toughness. The ASME Section XI ISI Program at DCPP has identified industry aging effects and has proven to maintain component structural integrity, and ensure that aging effects are discovered and repaired before the loss of component intended function.

Review of the second 10-year ISI Interval Summary Reports for 1R10, 1R11, 1R12, 1R13, 1R14, 1R15, 2R10, 2R11, 2R12, 2R13, and 2R14 indicates there were no aging related code repairs or code replacements required for continued service of ASME Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 Code components. The second 10-year ISI Interval Summary Reports reviewed did not indicate any program adequacy or implementation issues with the DCPP ASME Section XI Program for ASME IWB, IWC, and IWD code components.

An instance of accumulator nozzle cracking due to intergranular stress corrosion was identified in 1987. All nozzles were inspected and all nozzles that had unacceptable indications were weld-repaired or replaced with nozzles made of a new material.

Based on a review DCPP operating experience, relevant findings related to the ISI Program components have been identified and associated corrective actions have been taken.

The DCPP operating experience findings for this program identified no unique plant specific operating experience; therefore DCPP operating experience is consistent with NUREG-1801.

Conclusion

The continued implementation of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.3 Reactor Head Closure Studs

Program Description

The Reactor Head Closure Studs program manages cracking and loss of material by providing periodic ASME Section XI inspections of reactor vessel flange stud hole threads, reactor head closure studs, nuts, and washers. The program includes periodic visual and volumetric examinations of reactor vessel flange stud hole threads, reactor head closure studs, nuts, and washers and performs visual inspection of the reactor vessel flange closure during primary system leakage tests. The current DCPP ISI Program implements ASME Code Section XI, Subsection IWB (2001 Edition including the 2002 and 2003 Addenda) Table IWB-2500-1 and manages reactor vessel stud, nut, and washer cracking, loss of material, and reactor coolant leakage from the reactor vessel flange. Reactor vessel flange stud hole threads, reactor head closure studs, nuts, and washers are identified in ASME Code Section XI , Subsection IWB Table IWB-2500-1 and are within the scope of license renewal.

Each of the reactor vessel flange stud hole threads, reactor head closure studs, nuts, and washers is inspected for potential cracking and loss of material through visual and volumetric examinations in accordance with ASME Section XI Subsection IWB requirements in DCPP procedures once every 10 years. These inspections are conducted during refueling outages. Reactor vessel studs are removed from the reactor vessel flange each refueling outage. Repair and replacement activities associated with reactor vessel flange closure head stud hole threads, reactor head closure studs, nuts, and washers are in accordance with the requirements of ASME Section XI, IWA-4000. Preventive measures include coating the studs, nuts, and washers after inspection and storing in protective racks after removal, as recommended in Regulatory Guide 1.65, *Material and Inspection for Reactor Vessel Closure Studs*. Reactor vessel flange holes are plugged with water tight plugs during cavity flooding. These methods assure the holes, studs, nuts, and washers are protected from borated water during cavity flooding. The reactor vessel flange is inspected for leakage prior to reactor startup during reactor coolant system pressure testing each refueling outage.

NUREG-1801 Consistency
The Reactor Head Closure Studs program is an existing program that is consistent with exception to NUREG-1801, Section XI.M3, Reactor Head Closure Studs.

Exceptions to NUREG-1801

Program Elements Affected

Scope of Program - Element 1

NUREG-1801 specifies that this program is applicable to closure studs and nuts constructed from materials with a maximum tensile strength limited to less than 1,172 MPa (170 ksi). DCPP Certified Material Test Reports indicate that DCPP has four heats

heats that have an average ultimate tensile strength of 170.8 ksi, with a range of 160 ksi ksi to 175.5 ksi. DCPP credits inservice inspections that are within the scope of this AMP, which are implemented in accordance with the DCPP Inservice Inspection Program, Examination Category B-G-1 requirements as the basis for managing cracking cracking in these components. This is in accordance with the "parameters monitored or inspected" and "detection of aging effects" program elements in GALL AMP XI.M3.

Detection of Aging Effects - Element 4

NUREG-1801 specifies that surface examination uses magnetic particle, liquid penetration, or eddy current examinations to indicate the presence of surface discontinuities and flaws. The current DCPP ISI Program for the third interval implements ASME Code Section XI, Subsection IWB (2001 Edition including the 2002 and 2003 Addenda), which does not require surface examination. The current DCPP ISI Program requires visual and volumetric examinations in accordance with ASME Section XI Subsection IWA-2000 requirements. The future 120-month inspection interval for DCPP will incorporate the then-current requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval.

Enhancements

None

Operating Experience

A review of DCPP operating experience has not identified any SCC, IGSCC, galling or wear affecting the reactor vessel closure studs, nuts, washer, and flange thread holes. The Refueling Outage Inservice Inspection Summary Reports for Interval 2 (1996-2006) indicate there were no repair/replacement items identified involving reactor vessel closure studs, nuts, washers, or flange thread holes due to aging issues.

The DCPP operating experience findings for this program identified no unique plant specific operating experience; therefore DCPP operating experience is consistent with NUREG-1801. The Reactor Head Closure Studs program operating experience information provides objective evidence to support the conclusion that the effects of aging will be adequately managed so that the intended function of the reactor head closure stud bolting will be maintained during the period of extended operation.

The ISI Program at DCPP is updated to account for operating experience and code revisions as required by 10 CFR 50.55a(g)(4)(ii), at the end of each 120-month interval. ASME Section XI is also revised every three years and addenda issued in the interim,

which allows the code to be updated to reflect industry experience. The requirement to update the ISI Program to reference more recent editions of ASME Section XI at the end end of each inspection interval ensures the ISI Program reflects enhancements due to operating experience as well as changes incorporated into ASME Section XI.

Conclusion

The continued implementation of the Reactor Head Closure Studs program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.8 Steam Generator Tube Integrity

Program Description

The Steam Generator Tube Integrity program manages the aging of steam generator tubes, plugs, and tube supports. The scope of the program includes the preventive measures, inspections, degradation assessment, condition monitoring, operational assessment, tube plugging, and leakage monitoring activities necessary to manage potential steam generator tube degradation, including mechanically induced phenomena, phenomena, such as wear and impingement damage. The aging management measures employed includes nondestructive examinations, visual inspection, sludge removal, tube plugging, in-situ pressure testing and maintaining the chemistry environment by removal of impurities and addition of chemicals to control pH and oxygen. NDE inspection scope and frequency, and primary to secondary leak rate monitoring are conducted consistent with the requirements of DCPP Units 1 and 2 Technical Specifications and NEI 97-06, *Steam Generator Program Guidelines*. Tube structural integrity limits are applied consistent with Regulatory Guide 1.121, *Bases for Plugging Degraded PWR Steam Generator Tubes*, August 1976.

Guidance for steam generator management at DCPP is specified in plant procedures for steam generator tube integrity inspection and assessment, degradation assessment, maintenance, plugging or repair and primary to secondary leakage monitoring. Procedures also monitor and control secondary and primary side water chemistry. The DCPP steam generator tube inspection frequency is governed by the Technical Specifications and is evaluated as part of the Degradation Assessment performed prior to each refueling outage. Plugging criteria for removing tubes from service are consistent with the Technical Specifications.

The Steam Generator Tube Integrity program includes foreign material exclusion guidance, consistent with NEI 97-06. Plant procedural guidance includes measures to prevent the introduction of foreign material when access is provided to the primary and secondary sides of the steam generators. A secondary side foreign object search and retrieval effort is conducted when the hand hole covers are removed for maintenance to identify and remove loose parts and foreign material.

The Water Chemistry program (B2.1.2) mitigates the potentially corrosive effects of the primary and secondary water on the interior and exterior surfaces of the steam generator tubes and other steam generator internals.

Aging management activities for steam generator tubing integrity are controlled by plant procedures. DCPP procedural guidance includes performance criteria for tube structural structural integrity, operational leakage and accident induced leakage, and reporting criteria. The training and qualification standards for personnel engaged in non-destructive examination (NDE) activities are specified in a plant procedure. Inspection

practices are consistent with the EPRI PWR Steam Generator Examination Guidelines. DCPP programmatic guidance also requires that each inspection be based on a degradation assessment that considers DCPP historical data and industry operating experience from other similar steam generators.

The Degradation Assessment is performed to the guidelines of EPRI Steam Generator Integrity Assessment Guidelines, which covers degradation mechanisms, acceptable inspection techniques and sampling strategies. The Degradation Assessment assesses degradation of all components that affect steam generator tube integrity such as tubes, plugs and tube supports. Tube sleeves are not an approved method of repair at DCPP.

During each outage when the steam generator tubes are inspected or plugged, a Condition Monitoring and Operational Assessment is conducted to confirm that the structural and leakage integrity performance criteria have been satisfied. All degraded conditions identified during Steam Generator inspections are addressed in the DCPP corrective action program. All degraded steam generator tubes meeting the steam generator tube plugging criteria are removed from service by plugging.

NUREG-1801 Consistency

The Steam Generator Tube Integrity program is an existing program that is consistent with NUREG-1801, Section XI.M19, Steam Generator Tube Integrity.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Steam Generator Tube Integrity program tube inspection requirements are consistent with NEI 97-06. The program benefits from the industry operating experience available when the initiative was issued as well as the EPRI guidelines it endorses.

NRC Information Notice 97-88, *Experiences During Recent Steam Generator Inspections* addressed the importance of recognizing the potential for degradation in areas that have not previously experienced tube degradation and the importance of licensees to assess the significance of indications with respect to the qualification of the inspection techniques and the manner in which the indications were detected. The DCPP steam generator Degradation Assessment evaluates industry experience as well as DCPP experience to identify active, relevant and potential tube damage mechanisms.

mechanisms. Some of the important features of the Degradation Assessment include: choosing techniques to test for degradation based on the probability of detection and sizing capability, establishing the number of tubes to be inspected, establishing the structural limits, establishing the flaw growth rate or a plan to establish the flaw growth rate.

DCPP has replaced all four steam generators in each unit with Westinghouse Model Delta 54 steam generators, which contain Alloy 690 thermally treated tubes. The replacements took place during 2R14 in February 2008 for Unit 2 and 1R15 in February 2009 for Unit 1. A review of industry operating experience indicates that there have been no reported instances of cracking in thermally-treated Alloy 690 tubes at any U.S. plant. All degradation indications to date are from wear (fretting) due to loose parts, tube tube supports, anti-vibration bars, and manufacturing or handling anomalies. The tubing tubing and secondary internals in these units are more resistant to corrosion due to advanced material design.

Deleted: not susceptible

The DCPP operating experience findings for this program identified no unique plant specific operating experience; therefore DCPP operating experience is consistent with NUREG-1801. As additional Industry and applicable plant-specific operating experience become available, the Operating Experience (OE) will be evaluated and appropriately incorporated into the program through the DCPP Corrective Action and Operating Experience Programs. This ongoing review of OE will continue throughout the period of extended operation, and the results will be maintained on site. This process will confirm the effectiveness of this license renewal aging management program by incorporating applicable OE and performing self assessments of the program.

Conclusion

The continued implementation of the Steam Generator Tube Integrity program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. operation.

B2.1.10 Closed-Cycle Cooling Water System

Program Description

The Closed-Cycle Cooling Water (CCCW) System program manages loss of material, cracking and reduction of heat transfer for components in the closed-cycle cooling water systems. The program provides for: (1) preventive measures to minimize corrosion including maintenance of corrosion inhibitor, pH buffering agent, and biocide concentrations, and (2) periodic system and component performance testing and inspection. Preventive measures include the monitoring and control of corrosion inhibitors and other chemical parameters, such as pH, in accordance with the guidelines of EPRI TR-107396, Revision 1 (EPRI 1007820). Periodic inspection and testing to confirm function and monitor corrosion is performed in accordance with EPRI TR-107396, Revision 1 (EPRI 1007820), and industry and plant operating experience.

DCPP has four systems within the scope of license renewal that meet the definition for CCCW systems in GL 89-13 and portions of additional systems (heat exchangers or coolers) that are serviced directly by these systems. These CCCW systems are not subject to significant sources of contamination. The water chemistry is controlled in these systems and heat is not directly rejected to a heat sink.

The CCCW systems in License Renewal scope are:

- component cooling water (CCW) system
- service cooling water (SCW) system
- diesel engine jacket cooling water (DECW) system, a subsystem of the diesel generator system
- auxiliary building HVAC system

The program maintains water chemistry within the parameter limits specified in plant procedures and consistent with those in EPRI TR-107396, Revision 1 (EPRI 1007820), in order to minimize corrosion and microbiological growth. The chemicals added to the CCW and SCW systems are potassium molybdate (iron and aluminum corrosion inhibitor), potassium nitrite (iron corrosion inhibitor), tolyltriazole (TTA - a copper corrosion inhibitor), potassium tetra borate (buffering), potassium hydroxide (pH control), glutaraldehyde (biocide) and isothiazoline (biocide). The chemicals added to the DECW system are potassium dichromate and potassium hydroxide (corrosion inhibitors). The cooling water system associated with the auxiliary building HVAC system is maintained as a sealed pure water system based on potable water, without additives.

The CCCW System program periodically monitors system chemistry to verify it is being maintained in accordance with the guidelines of EPRI TR-107396, Revision 1 (EPRI 1007820), with stated exceptions, to minimize corrosion and SCC. In addition, non-chemistry testing and inspection techniques consistent with EPRI TR-107396, Revision 1 (EPRI 1007820), are used to confirm the effectiveness of the program.

The CCW pumps are periodically tested to verify pump performance. Non-destructive examinations are used to verify that the pressure boundary intended function of the CCW heat exchangers is maintained. Periodic performance testing of the CCW heat exchangers is part of the Open-Cycle Cooling Water System program (B2.1.9). Diesel engine performance parameters are monitored through periodic surveillance tests. These tests are used to monitor the performance of the DECW System components. Inspections are performed periodically on the in-scope DECW components.

The SCW system and the auxiliary building HVAC system chilled water systems are within the scope of license renewal per 10 CFR 54.4(a)(2) for spatial interaction concerns only. Therefore, the only component intended function applicable to these systems is (a)(2) leakage boundary (spatial). The periodic sampling and maintenance of system chemistry within specified limits are adequate to manage aging before the loss of this intended function.

NUREG-1801 Consistency

The Closed-Cycle Cooling Water System program is an existing program that, following enhancement, will be consistent with exception to NUREG-1801, Section XI.M21, Closed-Cycle Cooling Water.

Exceptions to NUREG-1801

Program Elements Affected

Preventive Actions - Element 2, Parameters Monitored/Inspected - Element 3, and Acceptance Criteria - Element 6

EPRI TR-107396, *Closed Cooling Water Chemistry Guideline*, Revision 1, Table 5-4, establishes a normal chromate concentration operating range of 150 - 300 ppm. DCPP Unit 1 and Unit 2 operate in the chromate concentration range of 1580 - 3150 ppm for the DECW System. The EPRI limit is based on the National Association of Corrosion Engineers (NACE) Report #7G181, 1981. This report investigated the influence of water treatment chemicals on mechanical seals and concluded that the degradation rate of some seals increased with the concentration of chromate. DCPP has not observed seal failures that were attributed to the concentration of chromates in the DECW System. DCPP operating experience and recent industry research on the subject provide evidence that supports DCPP operating at chromate concentration levels greater than those established by the EPRI Closed Cooling Water Chemistry Guideline.

Preventive Actions - Element 2 and Parameters Monitored/Inspected - Element 3

EPRI TR-107396, *Closed Cooling Water Chemistry Guideline*, Revision 1, Table 5-4 establishes chloride and fluoride as control parameters to be monitored monthly. DCPP Unit 1 and Unit 2 do not monitor or analyze chloride and fluoride in the DECW system. The makeup water to the DECW system is demineralized and there are no known pathways for chloride or fluoride to enter the jacket cooling water. Also, chromates are anodic inhibitors and the concentration in the jacket cooling water is maintained above a level that prevents the onset of pitting corrosion due to chloride and fluoride.

Preventive Actions - Element 2, Parameters Monitored/Inspected - Element 3

EPRI TR-107396, *Closed Cooling Water Chemistry Guideline*, Revision 1, Table 5-4 establishes a monthly monitoring frequency for DECW control parameters under stable conditions. DCPP Unit 1 and Unit 2 currently perform a quarterly monitoring frequency for these DECW control parameters under stable conditions. The jacket cooling water chemistry has remained stable at DCPP for over 25 years. Increasing the sampling frequency would increase the amount of hazardous waste generated, and the amount of makeup required to replace the sample and purge volume. In addition, the jacket cooling water is an isolated system and contamination of the coolant is not expected. The high chromate concentration maintained at DCPP results in a very tenacious protective oxide corrosion layer that has a minimal corrosion rate.

Parameters Monitored or Inspected - Element 3, Detection of Aging Effects - Element 4, and Monitoring and Trending - Element 5

NUREG-1801, Section XI.M21, Element 3, states that the CCCW Program should monitor heat exchanger parameters including flow, inlet and outlet temperatures, and differential pressure. NUREG-1801, Section XI.M21, Element 4, states that performance and functional testing ensures acceptable functioning of the CCCW system system or components serviced by the CCCW system. NUREG-1801, Section XI.M21, Element 5, states that internal visual inspections and performance/functional tests are to to be performed periodically to confirm the effectiveness of the program. Exception is taken to performance testing and inspection of the heat exchangers served by the CCCW systems. At DCPP, performance/ functional testing and inspection of the heat exchangers served by the in-scope CCCW systems are not performed as part of the CCCW Program. EPRI TR-107396, Revision 1 (EPRI 1007820), Section 8.4.4, states that performance testing is typically part of an engineering program, as opposed to a CCCW program. Functional and performance testing verify that component active functions can be accomplished, and as such the testing is within the scope of the Maintenance Rule (10 CFR 50.65). The CCCW Program utilizes corrosion monitoring which includes component inspections to monitor program effectiveness in managing component degradation that could impact a passive function. Chemical analysis of iron and copper in the bulk water is performed to monitor the buildup of dissolved corrosion products. Higher than expected concentration levels of total iron and copper indicate

possible corrosion within the closed-cycle cooling water systems. Measurement of accumulated corrosion products such as iron and copper provides an indirect indication of system corrosion.

DCPP employs non-chemistry testing and inspection techniques consistent with EPRI TR-107396, Revision 1 (EPRI 1007820), Section 8.4 (Non-Chemistry Monitoring), to evaluate system and component performance, determine the potential for loss of material or leakage caused by corrosion or SCC, and to monitor the potential for decreased flow capacity and heat transfer degradation caused by fouling. Plant procedures set forth testing and inspection requirements and frequency of performance. The techniques include thermal performance testing (performed on the CCW heat exchangers as part of the Open-Cycle Cooling Water Program), flow testing, operability testing and visual inspections. Visual inspections of the CCW supply isolation check valves to the reactor coolant pumps (valves CCW-1-585 and CCW-2-585) are used as a leading indicator of the condition of the interior of piping components otherwise inaccessible for visual inspection. This periodic internal inspection will detect loss of material and fouling.

Corrosion test loops using corrosion coupons are in place for Unit 1 and Unit 2 in the CCW and SCW Systems. These coupons have been visually examined with no detectible corrosion. Corrosion spool pieces with an orifice to create low flow are installed for the CCW System in Unit 1 and Unit 2. These are visually examined to detect bio-fouling. If bio-fouling is observed, potential surface corrosion will be evaluated to determine if a sample should be sent off for bacteria culture analysis to determine if there is MIC-type bacteria.

In lieu of performance testing and inspection of the heat exchangers served by the DECW system, diesel engine performance testing monitors various engine parameters monthly to validate the operability of the engines and to verify the performance of both the heat exchangers and pumps.

The diesel engine generator jacket cooling pumps, diesel engine generator jacket water after-coolers, diesel engine jacket water radiators and diesel engine lube oil heat exchangers are not individually monitored for flow, inlet and outlet temperatures and differential pressure and internal visual inspections are not performed on each component. At DCPP, diesel engine performance parameters are monitored through periodic Technical Specification surveillance tests and internal visual inspections of selected components that serve as leading indicators for the condition of surfaces exposed to closed-cycle cooling water. Diesel engine generator performance testing monitors various engine parameters to validate the operability of the engines and to verify the performance of both the heat exchangers and the pumps. Test data gathered includes DECW system cooling system levels, temperature and pressures from which the DECW heat exchanger performance and pump performance can be inferred. Trending of these parameters will detect component aging prior to loss of intended function. The jacket water after coolers are hydro tested. The jacket water radiators are

are visually inspected and cleaned. The diesel engine lube oil heat exchangers are internally inspected visually. The surveillance tests together with periodic hydro and internal visual inspections and the periodic sampling and control of system water chemistry are adequate to ensure the component intended functions are maintained within the DECW system.

EPRI TR-107396, Revision 1 (EPRI 1007820), Section 8.2, addresses fouling and indicates that fouling is unlikely to be significant for component surfaces exposed to closed cooling water. It states that control of both corrosion and microbiological growth will prevent fouling of CCCW systems and that visual examination is one of the most effective methods of determining the extent of fouling. For many heat exchangers, fouling of the closed cooling water side surfaces is insignificant compared with fouling on the opposite side of the heat exchanger and therefore reductions in the overall heat transfer coefficient may not be related to fouling of the closed cooling water side heat exchange surfaces. Raw water system heat exchangers are a primary example.

The DCPP position is consistent with the EPRI approach. Reductions in heat transfer are managed through a combination of chemistry controls and inspection activities. Chemistry controls are generally adequate to prevent buildup of significant fouling on heat exchanger surfaces. Periodic inspections are used to confirm the condition of component surfaces, including heat exchange surfaces.

The heat exchangers served by the CCCW systems that are in scope of license renewal per 10 CFR 54.4(a)(2) for spatial interaction concerns only, are not tested or inspected. The only intended function of these heat exchangers is (a)(2) leakage boundary (spatial). Periodic sampling and maintenance of system chemistry are adequate to manage aging for these components before the loss of intended function.

Preventive Actions - Element 2, Parameters Monitored/Inspected - Element 3, Detection of Aging Effects - Element 4, Monitoring and Trending - Element 5, Acceptance Criteria - Element 6, and Corrective Actions - Element 7

The program described in NUREG-1801, Section XI.M21, is based on the 1997 version of the EPRI Closed Cooling Water Chemistry Guideline, TR-107396, Revision 0. The DCPP CCCW System program currently uses the 2004 version of the EPRI Closed Cooling Water Chemistry Guideline, Revision 1. This exception is acceptable because the EPRI Closed Cooling Water Chemistry Guideline is a consensus document that is updated based on new operating experience, research data, and expert opinion. Incorporation of later versions of the guidance document ensures that the program addresses new information. DCPP has reviewed EPRI Closed Cooling Water Chemistry Chemistry Guideline, Revision 1, and has determined that the most significant difference difference is that the new revision provides more prescriptive guidance and has a more conservative monitoring approach. The new revision meets the same requirements of EPRI TR-107396, Revision 0, for maintaining conditions to minimize corrosion and

microbiological growth in closed cooling water systems for effectively mitigating many aging effects.

Enhancements

Prior to the period of extended operation, the following enhancements will be implemented in the following program element:

Monitoring and Trending - Element 5

DCPP will utilize inspections of the CCW supply isolation check valves to the reactor coolant pumps (valves CCW-1-585 and CCW-2-585) as a leading indicator of the condition of the interior of piping components otherwise inaccessible for visual inspection. This periodic internal inspection will detect loss of material and fouling. The inspections are scheduled to be performed for Unit 1 and for Unit 2 at least once every five years. Plant procedures will be enhanced to include the acceptance criteria.

Monitoring and Trending - Element 5

DCPP will monitor the corrosion of closed cooling water components by inspecting the condition of corrosion coupons installed in the system and perform internal inspections of select components within the systems. These methods will verify that wetted material exposed to the chemistry of the closed cooling water systems are not experiencing corrosion. The corrosion coupons are strips of metal (i.e. copper, carbon steel, stainless steel, etc) that are installed in the closed cooling water systems in a manner such that they are exposed to the cooling water. Periodically these coupons are removed and their condition can be evaluated. This inspection will provide DCPP indication if significant corrosion is occurring in the system. The material of these corrosion coupons is representative of most of the materials that are used in the system. For those components that do not have material represented by the corrosion coupons, internal inspections will be performed on those components, or other component with similar material, in order to monitor for corrosion.

Operating Experience

The CCCW System program is based on the guidance contained in EPRI TR-107396, Revision 1 (EPRI 1007820), which itself is based on industry-wide operating experience, research data, and expert opinion. The guideline is periodically updated and approved by the industry using a consensus process.

DCPP operating experience is evaluated and corrective actions are implemented for chemical concentrations, monitoring and testing, thereby minimizing aging effects to ensure adherence to EPRI TR-107396, Revision 1 (EPRI 1007820). This is

accomplished by promptly identifying and documenting (using the Corrective Action Program) any conditions that indicates degradation of the DCPP CCCW systems. In addition, industry operating experience, self assessments and independent audits provide additional input to ensure that program operability is maintained at an optimum level.

In 1995, biofouling was discovered in the CCW system. CCW heat exchanger thermal performance testing demonstrated no downward trend of heat transfer since the discovery of biological activity in the CCW System.

In 2005, biofouling was observed in the SCW system. Corrective actions included chemical and mechanical cleaning of the heat exchangers. Chemicals such as glutaraldehyde and isothiazoline are added to the SCW system to control biological material. Measurement of bacteria is performed periodically to provide indications of biological activity averse to aging.

A review of CCCW heat exchanger performance testing results performed per plant procedures confirmed that the DCPP CCCW System program is capable of ensuring that the intended functions of the closed-cycle cooling water systems are not compromised by aging. Based on a review of DCPP operating experience, any chemistry parameters outside of established limits have been identified and the appropriate actions taken. Corrective actions have included increasing sampling frequencies, chemical addition, and feed and bleeds. The DCPP operating experience findings for this program identified no unique plant specific operating experience; therefore DCPP operating experience is consistent with NUREG-1801.

The CCCW System operating experience information provides objective evidence to support the conclusion that the effects of aging will be adequately managed so that the structure and component intended functions will be maintained during the period of extended operation.

Conclusion

The continued implementation of the Closed-Cycle Cooling Water program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.17 Selective Leaching of Materials

Program Description

The Selective Leaching of Materials program manages loss of material due to selective leaching for brass (>15 percent zinc), gray cast iron, and aluminum-bronze (>8 percent aluminum) components within the scope of license renewal that are exposed to raw water, including condensation, and treated water. The program provides measures for detecting the aging effects prior to loss of intended function, but does not prevent degradation due to aging effects. There is no monitoring and trending for the one-time inspection activity.

The Selective Leaching of Materials program includes a one-time visual inspection and hardness measurement or other industry-accepted mechanical inspection techniques (where feasible based on form and configuration) of selected components that may be susceptible to selective leaching to determine whether loss of material due to selective leaching is occurring. Evidence of selective leaching discovered in the initial implementation of the program is submitted for engineering evaluation. The engineering engineering evaluation will determine whether the potential loss of material affects the ability of the components to perform their intended function. The results of the engineering evaluation will also determine the extent of expansion of the sample size and locations for additional inspections and evaluations. Follow-up examinations or evaluations are performed as required to ensure component functionality during the period of extended operation. Industry-accepted mechanical methods of testing for selective leaching may include scraping or chipping of the surfaces.

Deleted: need to expand

The Selective Leaching of Materials program is a new program and the inspections will be completed within the 10-year period prior to the period of extended operation.

NUREG-1801 Consistency

The Selective Leaching of Materials program is a new program that, when implemented, will be consistent with NUREG-1801, Section XI.M33, Selective Leaching of Materials.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Selective Leaching of Materials program is a new program at DCPP. Therefore, there is no plant-specific operating experience for program effectiveness. Industry

operating experience that forms the basis for this program is included in the operating experience element of the corresponding NUREG-1801, aging management program description. The DCPP operating experience findings for this program identified no unique plant specific operating experience; therefore DCPP operating experience is consistent with NUREG-1801. The only plant operating experience identified in the review was the response to NRC Information Notice 94-59, *Accelerated Dealloying of Cast Aluminum-Bronze Valves Caused by Microbiologically Induced Corrosion,* which documented an evaluation that was completed for selective leaching. Upon completing the evaluation, DCPP concluded that biocide injection, periodic inspection and cleaning had been maintaining the affected components operable. In 1997, signs of selective leaching were noted on three valves in the auxiliary saltwater system. Polished counterweights and housings were installed to slow the rate of de-alloying. Subsequent visual inspections of the subject valves, performed every 18 months, have not identified any selective leaching issues since this implementation. Therefore, the existing plant maintenance practices have proven to be adequate for identification of selective leaching and periodic inspections of valves susceptible to selective leaching.

Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. As additional industry and applicable plant-specific operating experience become available, the operating experience will be evaluated and appropriately incorporated into the program through the DCPP Corrective Action Program and Operating Experience Program. This ongoing review of operating experience will continue throughout the period of extended operation, and the results will be maintained on site. This process will confirm the effectiveness of this new program by incorporating applicable operating experience and performing self assessments of the program.

Conclusion

The implementation of the Selective Leaching of Materials program will provide reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.19 One-Time Inspection of ASME Code Class 1 Small-Bore Piping

Program Description

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program manages cracking of ASME Code Class 1 piping less than or equal to four inches nominal pipe size (NPS 4). This program is implemented as part of the fourth interval of the DCPP Inservice Inspection (ISI) program.

For ASME Code Class 1 small-bore piping, the ISI program requires volumetric examinations on selected butt weld locations to detect cracking. Weld locations are selected based on the guidelines provided in EPRI TR-112657, *Revised Risk-Informed Inservice Inspection Evaluation Procedure*. Volumetric examinations are conducted in accordance with ASME Section XI with acceptance criteria from Paragraph IWB-3000 and IWB-2430. The fourth interval of the ISI program at DCPP, beginning in 2015 for Unit 1 and 2016 for Unit 2, will provide the results for the one-time inspection of ASME Code Class 1 small-bore piping. A minimum of two socket weld locations per unit will be be volumetrically inspected. For volumetric examinations of socket welds, DCPP will use a site developed and qualified procedure. DCPP will evaluate the need to enhance this procedure with the latest industry techniques at the time of the volumetric examination. DCPP has not experienced cracking of ASME Code Class 1 small bore pipe butt welds less than or equal to NPS 4.

Deleted: Currently, a reliable and effective volumetric examination to detect cracking in socket welds and piping less than NPS 1 is not available. The DCPP ISI program performs periodic VT-2 visual examinations of ASME Class I piping socket welds and piping less than NPS 1 during each refueling outage.

In conformance with 10 CFR 50.55a(g)(4)(ii), the DCPP ISI Program is updated each successive 120 month inspection interval to comply with the requirements of the latest edition of the ASME Code specified twelve months before the start of the inspection interval.

DCPP inspects ASME Code Class 1 piping less than or equal to NPS 4 through the RI-ISI Program. To determine the selection of elements for examination, degradation mechanisms were assessed and a consequence evaluation was completed in order to perform a risk ranking of the piping segments within the scope of the RI-ISI program. A risk matrix was created with categories for high, medium and low risk. Elements for examination were selected such that 25 percent of the elements in the high risk category were selected, 10 percent of the elements in the medium risk region were selected, and no elements from the low risk region were selected.

The RI-ISI Program for pipe welds employs the EPRI methodology as described in EPRI EPRI Topical Report TR 112657, Revision. B. The selection for examination of specific elements within a segment is based on the degradation mechanism, as well as inspection cost, radiation exposure and accessibility. Other considerations that go into the element selection process are inspectability, distribution of inspections among systems and segments, plant specific inspection results, and repairs or remedial measures which have been implemented.

Deleted: to

NUREG-1801 Consistency

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program is an existing program that is consistent with exception to NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class 1 Small-Bore Piping.

Exceptions to NUREG-1801

Program Elements Affected

Scope of Program - Element 1

NUREG-1801 recommends the use of EPRI Report 1000701, *Interim Thermal Fatigue Management Guideline* (MRP-24), January 2001, for identifying piping susceptible to potential effects of thermal stratification or turbulent penetration. The DCPP risk-informed process examination requirements are performed consistent with EPRI TR-112657, *Revised Risk-Informed Inservice Inspection Evaluation Procedure*, Revision B, instead of EPRI Report 1000701. Guidelines for identifying piping susceptible to potential effects of thermal stratification or turbulent penetration that are provided in EPRI Report 1000701 are also provided in EPRI TR-112657. The recommended inspection volumes for welds in EPRI Report 1000701 are identical to those for inspection of thermal fatigue in RI-ISI programs; thus, the DCPP risk-informed process examination requirements meet the recommendations of NUREG-1801. The NRC accepted DCPP's use of EPRI TR-112657 in a letter to PG&E dated November 8, 2001.

Enhancements

None

Operating Experience

Operating experience at DCPP is evaluated and implemented to ensure ASME Code Class 1 small-bore pipes are maintained within acceptable limits. This is accomplished by promptly identifying and documenting (using the corrective action program) any conditions that indicate degradation. In addition, industry operating experience, self assessments and independent audits provide additional input to ensure that program effectiveness is maintained.

A review of plant-specific operating experience identified two examples of cracking in ASME Code Class 1 small-bore pipe welds less than or equal to NPS 4. The following two examples identify weld cracking at DCPP:

1) A cracked weld coupling on a pressurizer level instrument capillary fill line evaluation concluded that the crack was due to a lack of fusion to the tubing and previous metal removal resulting in fatigue cracking. New tubing was installed.

Deleted: indicates no

Deleted: has been observed for

Deleted: butt

Deleted: Although not within the scope of this program, the

2) A 1~~4~~-inch excess letdown piping reducer segment socket weld showed a crack indication. The evaluation concluded that the likely cause was due to inter-granular stress corrosion cracking caused by sensitization of the base metal as a result of the initial weld process. The piping was replaced and a fatigue resistant weld was used.

Follow-up inspections at these locations have not identified any further evidence of weld cracking. This demonstrates the effectiveness of the DCPP Corrective Action program.

Inservice Inspection Reports for the Second Interval were reviewed for Unit 1 Refueling Outages 10, 11, 12 and 13 and Unit 2 Refueling Outages 10, 11, 12 and 13. There were no reportable indications for small-bore piping observed.

The DCPP operating experience findings for this program identified no unique plant specific operating experience; therefore DCPP operating experience is consistent with NUREG-1801. Should evidence of significant aging be revealed by the one-time inspection, periodic inspections will be implemented.

Based on a review of operating experience, cracking of ASME Code Class 1 small-bore pipe butt welds less than or equal to NPS 4 has not been observed. This provides confidence that the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program is adequate to assure that aging of ASME Code Class 1 piping is not occurring and component intended functions will be maintained during the period of extended operation.

Conclusion

The continued implementation of the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.36 Metal Enclosed Bus

Program Description

The Diablo Canyon metal enclosed bus program manages aging of in-scope non-segregated phase and isolated phase bus.

The Metal Enclosed Bus program manages the aging effects of loose connections, embrittlement, cracking, melting, swelling, or discoloration of insulation, loss of material of bus enclosure assemblies, hardening of boots and gaskets, and cracking of internal bus supports to ensure that metal enclosed buses within the scope of license renewal are capable of performing their intended function. The Metal Enclosed Buses (MEBs) within the scope of this program are the MEBs that are used during station blackout recovery. DCPP is currently performing metal enclosed bus work order inspection activities in response to DCPP plant-specific operating experience. The scope of metal enclosed bus sections in the existing DCPP maintenance inspections include non-segregated phase bus sections and isolated phase bus sections that are specifically included within the scope of license renewal due to being part of the station blackout recovery path and conservatively includes other metal enclosed sections whose failure could effect the station blackout recovery buses.

Deleted:

Prior to the period of extended operation and every 10 years thereafter, internal portions of in-scope non-segregated phase MEBs are visually inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus insulation on the non-segregated phase bus is inspected for signs of embrittlement, cracking, melting, swelling, hardening or discoloration, which may indicate overheating or aging degradation. The internal bus supports are inspected for structural integrity and signs of cracks. The bus enclosure assemblies are inspected for loss of material due to corrosion and hardening of boots and gaskets.

Prior to the period of extended operation and every 10 years thereafter a sample of the in-scope non-segregated phase MEB accessible bolted connections are checked for evidence of overheating. Contact resistance test or thermography is performed on a sample of the accessible connections. As an alternative to thermography or measuring connection resistance of bolted connections, for the accessible bolted connections that are covered with insulating material DCPP may use visual inspection of insulation material to detect surface anomalies, such as discoloration, cracking, chipping or surface contamination. If this alternative visual inspection is used to check bolted connections, the first inspection will be completed prior to the period of extended operation and every five years thereafter.

Deleted:

Deleted: is

The acceptance criteria for thermography testing will be based on the temperature rise above the reference temperature. The reference temperature will be ambient temperatures or the baseline temperature data from the same type of connections being being tested. When contact resistance testing is used the accepted value shall be based on the type of test used and the configuration of the connection. The acceptance

acceptance criterion for insulation material covering bolted connections is the absence of heat related anomalies.

The isolated phase portion of the program manages the effects of cracking and loss of material of bus enclosure assemblies, hardening of gaskets, and cracking of internal bus supports to ensure that isolated phase metal enclosed buses within the scope of license renewal are capable of performing their intended function. The isolated phase bus does not have bus insulation installed.

Prior to the period of extended operation and every 10 years thereafter, internal portions of the in-scope isolated phase MEBs are visually inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The internal bus supports are inspected for structural integrity and signs of cracks. The bus enclosure assemblies are inspected for loss of material due to corrosion and hardening of gaskets. The isolated phase segments are welded and not bolted.

Additional investigation and evaluation will be performed when the acceptance criteria are not met. Corrective actions may include but are not limited to cleaning, drying, increased inspection frequency, replacement, or repair of the affected MEB components. When an unacceptable condition or situation is identified, a determination will be made as to whether the same condition or situation is applicable to other accessible or inaccessible MEBs.

The MEB program is an inspection program. No actions are taken as part of this program to prevent or mitigate aging degradation. Trending actions are not included as part of this program because the ability to trend inspection results is limited.

NUREG-1801 Consistency

The Metal Enclosed Bus program is an existing program that, following enhancement, will be consistent with exception to NUREG-1801, Section XI.E4, Metal Enclosed Bus.

Exceptions to NUREG-1801

The bus segments are not wrapped with insulation or have boots, as is the non-segregated bus. Therefore, inspection of insulation and boots is not applicable. Most of of the Isophase bus sections are welded together. Resistance checks or infrared inspections area not required for welded connections. There are 3 locations of bolted connections within the Isophase bus. These connections are inspected as part of Metal Enclosed Bus program. PG&E manages bolted connections at the ends of the isolated phase bus under the maintenance programs of the motor operated disconnect, the main main unit transformers, and the auxiliary transformers. The bolted connections that are part of active components are not within the scope of this aging management program.

Deleted: None

Enhancements

Prior to the period of extended operation, the following enhancement will be implemented in the following program elements:

Scope of Program - Element 1, Preventive Actions - Element 3, Detection of Aging Effects - Element 4, Acceptance Criteria - Element 6 and Corrective Actions - Element 7

The existing bus work order inspection activities for inspection and testing of the MEBs will be proceduralized to include specific inspection scope, frequencies and actions to be taken when acceptance criteria are not met.

Operating Experience

Industry experience has shown that failures have occurred on metal enclosed buses caused by cracked insulation and moisture or debris buildup internal to the metal enclosed bus. Experience has also shown that bus connections in the metal enclosed buses exposed to appreciable ohmic heating during operation may experience loosening due to repeated cycling of connected loads. NRC Information Notice 2000-14, *Non-Vital Bus Fault Leads to Fire and Loss of Offsite Power* and Information Notice 89-94, *Electrical Bus Bar Failures* are examples of non-segregated bus duct failures.

NRC Information Notice 2000-14 discusses a 12 kV Bus fault that occurred on DCPP Unit 1. The corrective actions, in response to the event included:

- Replaced aluminum bus with copper
- Added Belleville washers to bolted connections. The washers are non-electroplated to preclude hydrogen embrittlement.
- Bus cleaning, micro-ohm testing and bolting retorque

A review of plant operating experience identified four instances of cracked welds in the 25 kV isolated phase bus neutral enclosures and three instances of cracked, corroded or or loose 4 kV bus supports. In addition, instances of Noryl insulation aging were identified during MEB work order inspection activities in the 4 kV bus and the 12 kV aluminum bus ducts that were found to be corroded. All deficiencies were repaired. A periodic bus inspection has been implemented to assure bus availability.

Deleted: iso-phase

Deleted: bus

The DCPP operating experience findings for this program identified no unique plant specific operating experience; therefore DCPP operating experience is consistent with NUREG-1801.

Conclusion

The continued implementation of Metal Enclosed Bus program will provide reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

Table 3.6.2-1 Electrical and Instrument and Controls – Summary of Aging Management Evaluation – Electrical Components

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Metal Enclosed Bus (Enclosure)	SS	Aluminum	Atmosphere/ Weather (Ext)	Loss of material	Aging Management Program for Metal Enclosed Bus (B2.1.36)	None	None	F
Metal Enclosed Bus (Enclosure)	SS	Aluminum	Plant Indoor Air (Ext)	Loss of material	Aging Management Program for Metal Enclosed Bus (B2.1.36)	None	None	F

F Material not in NUREG-1801 for this component.

Table A4-1 License Renewal Commitments

Item #	Commitment	LRA Section	Implementation Schedule
30	DCPP will monitor the corrosion of closed cooling water components by inspecting the condition of corrosion coupons installed in the system and perform internal inspections of select components within the systems. These methods will verify that wetted material exposed to the chemistry of the closed cooling water systems are not experiencing corrosion. The corrosion coupons are strips of metal (i.e. copper, carbon steel, stainless steel, etc) that are installed in the closed cooling water systems in a manner such that they are exposed to the cooling water. Periodically these coupons are removed and their condition can be evaluated. This inspection will provide DCPP indication if significant corrosion is occurring in the system. The material of these corrosion coupons is representative of most of the materials that are used in the system. For those components that do not have material represented by the corrosion coupons, internal inspections will be performed on those components, or other component with similar material, in order to monitor for corrosion.	B2.1.10	Prior to the period of extended operation

Enclosure 1

License Renewal Application Amendment 5 and Methodology Summary

In PG&E letter DCL-10-067, dated June 18, 2010, PG&E responded to request for additional information (RAI) 2.3-4 and committed to add high energy systems in the turbine building into the scope of license renewal. These systems are being added because these high energy systems could interact with safety-related electrical cable in the turbine building. The preventive approach is being used for the high energy systems in order to provide added assurance that safety-related cable in the turbine building is not damaged by the effects of pipe whip and jet impingement due to the potential aging-related failure of a high energy component.

The high energy systems in the Diablo Canyon Power Plant (DCPP) turbine building were identified based on the plant licensing basis. The high energy portions of the following systems were evaluated and included within the scope of license renewal. An aging evaluation has been performed, and the corresponding license renewal application (LRA) sections and tables have been revised. The corresponding tables in Chapter 3 were also revised. The following systems or portions of systems in the turbine building contain high energy. These high energy systems were added to the scope of license renewal:

- Extraction steam and heater drip system (2.3.3.18)
- Turbine generator and associated systems (2.3.3.18)
- Secondary sampling system (2.3.3.18)
- Turbine steam supply system (2.3.4.1)
- Auxiliary steam system (2.3.4.2)
- Feedwater system (2.3.4.3)
- Condensate system (2.3.4.4)

The components in the portions of the above systems that were added to scope were evaluated using the methodology as described in Chapter 2. The newly added components were evaluated, and any new materials or environments were identified and added to the materials, environments, aging effects, and aging management programs list contained in Chapter 3. Additionally the Chapter 3 tables were revised to reflect the results of the aging evaluations of the newly added components. The LRA page changes included in this amendment only show text and individual table line items that have been added or deleted from the previous amendment (with exception to Table 2.2-1, for the purpose of clarity). Existing text and table line items that did not change have not been included in this amendment.

In addition to the changes resulting from the addition of high energy systems, there are also revisions to screening and aging management review results identified due to the adjustment of the scoping boundary and identification of corrections that were needed.

List of Revised License Renewal Application Sections and Tables

Table/Section No.	Name
Section 2.3.3.18	Miscellaneous Systems In Scope ONLY for Criterion 10 CFR 54.4(a)(2)
Section 2.3.4.1	Turbine Steam Supply System
Section 2.3.4.2	Auxiliary Steam System
Section 2.3.4.3	Feedwater System
Section 2.3.4.4	Condensate System
Section 3.3.2.1.18	Miscellaneous Systems In-Scope ONLY based on Criterion 10 CFR 54.4(a)(2)
Section 3.4.2.1.1	Turbine Steam Supply System
Section 3.4.2.1.2	Auxiliary Steam System
Section 3.4.2.1.4	Condensate System
Table 2.2-1	DCPP Scoping Results
Table 2.3.3-18	Miscellaneous Systems In Scope ONLY Based on Criterion 10 CFR 54.4(a)(2)
Table 2.3.4-1	Turbine Steam Supply System
Table 2.3.4-2	Auxiliary Steam System
Table 2.3.4-3	Feedwater System
Table 2.3.4-4	Condensate System
Table 3.3.1	Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems
Table 3.3.2-18	Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2)
Table 3.4.1	Summary of Aging Management Evaluations in Chapter VIII of NUREG-1801 for Steam and Power Conversion System
Table 3.4.2-1	Steam and Power Conversion System – Summary of Aging Management Evaluation – Turbine Steam Supply System
Table 3.4.2-2	Steam and Power Conversion System – Summary of Aging Management Evaluation – Auxiliary Steam System
Table 3.4.2-3	Steam and Power Conversion System – Summary of Aging Management Evaluation – Feedwater System
Table 3.4.2-4	Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System
Appendix B2.1.10	Closed-Cycle Cooling Water System

2.3.3.18 Miscellaneous Systems In Scope ONLY for Criterion 10 CFR 54.4(a)(2)

The following systems are within the scope of license renewal only based on the criterion of 10 CFR 54.4(a)(2):

- Turbine generator associated systems

Formatted: Bullets and Numbering

System Descriptions/System Intended Functions

Extraction steam and heater drip system

The purpose of the extraction steam and heater drip system is to provide preheated feedwater to the steam generators to improve cycle efficiency.

Extraction steam from the high pressure turbine and drains from the moisture separator reheaters are used to heat the feedwater in the last two stages of the feedwater heaters. Extraction steam from the low pressure turbines is used to heat the feedwater in the first four stages of the feedwater heaters. The extraction steam and heater drip system is nonsafety and performs no safety-related functions.

The extraction steam and heater drip system contains nonsafety piping that is located within safety-related areas. The extraction steam and heater drip system piping and piping components in the turbine building contain high energy fluids.

The majority of the extraction steam and heater drip system consists of piping which contains high energy fluids located in the turbine building where there are some safety related cables. There is also a portion of system piping located in the auxiliary building. Therefore, portions of the extraction steam and heater drip system are within the scope of license renewal as nonsafety-related affecting safety-related components based on the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

Deleted: Portions

Secondary Sampling System

The secondary sampling system is a nonsafety-related system that provides sampling and analysis of secondary plant systems.

The central sample panel for each unit is located in the auxiliary building. Each unit has another sample panel located in the buttress area west of the turbine building. Most of the sample points and lines are in the turbine building but the lines leading to the central sample panels are in the auxiliary building. Portions of the secondary sampling system piping and piping components in the turbine building contain high energy fluids.

Portions of the secondary sampling system are in scope as nonsafety affecting safety-related components based on the criterion of 10 CFR 54.4(a)(2) due to spatial interaction and structural integrity. High energy portions of the secondary sampling system in the turbine building could prevent the satisfactory accomplishment of a safety-related function associated with certain safety-related cables. These portions of the secondary sampling system are within the scope of license renewal as nonsafety affecting safety-related components based on the criterion of 10 CFR 54.4(a)(2).

Formatted: LRA Text

Turbine Generator Associated Systems

The purpose of the turbine generator associated systems is to support operation of the main turbine and generator by supplying turbine shaft sealing, generator shaft sealing, generator gas cooling, and generator water cooling. It also supplies shaft sealing for the main feed pump turbines. It includes the following systems:

- Gland sealing system, which prevents air leakage into the turbine along the shaft
- Hydrogen cooling for the main generator
- Generator seal oil, which prevents hydrogen from leaking from the main generator
- Stator cooling water system

Formatted: Bullets and Numbering

The turbine generator associated systems do not perform any safety functions.

The turbine generator associated systems piping and piping components in the turbine building contain high energy fluids.

The high energy portions of the turbine generator associated systems in the turbine building could prevent the satisfactory accomplishment of a safety-related function associated with certain safety-related cables. Therefore, portions of the turbine generator associated systems are within the scope of license renewal as nonsafety-related affecting safety-related components based on the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

FSAR References

Details of the extraction steam and heater drip system are discussed in FSAR Sections 3.6.1.2, 10.2.2.1, and 10.4.7.2.

Details of the radiation monitoring system (mechanical) system are discussed in FSAR Sections 11.4.1, 11.4.2.2, and Table 11.4-1.

Details of the sanitary sewage system are discussed in FSAR Section 9.2.8.

Details of the secondary sampling system are discussed in FSAR Sections 3.6.1.2 and 9.3.2.3.

Details of the service cooling water system are discussed in FSAR Section 9.2.1.

Details of the solid radwaste system are discussed in FSAR Sections 11.2 and 11.5.

Details of the turbine generator associated systems are discussed in FSAR Sections 3.6.1.2, 10.2.2.3, and 10.4.3.

License Renewal Boundary Drawings

The license renewal boundary drawings for the extraction steam and heater drip system are listed below:

LR-DCPP-05-106705-02
LR-DCPP-05-106705-03
LR-DCPP-05-106705-04
LR-DCPP-05-106705-05
LR-DCPP-05-106705-06
LR-DCPP-05-106705-07
LR-DCPP-05-107705-02
LR-DCPP-05-107705-03
LR-DCPP-05-107705-05
LR-DCPP-05-107705-06
LR-DCPP-05-107705-07
LR-DCPP-28-106728-04
LR-DCPP-28-106728-05
LR-DCPP-28-107728-04
LR-DCPP-28-107728-05

The license renewal boundary drawings for the secondary sampling system are listed below:

LR-DCPP-02-106702-02
LR-DCPP-02-106702-03
LR-DCPP-02-106702-04
LR-DCPP-02-106702-05
LR-DCPP-02-106702-08
LR-DCPP-02-107702-02
LR-DCPP-02-107702-03
LR-DCPP-02-107702-05
LR-DCPP-02-107702-08
LR-DCPP-02-107702-14
LR-DCPP-03-106703-02
LR-DCPP-04-106704-02
LR-DCPP-04-106704-03
LR-DCPP-04-106704-05
LR-DCPP-04-106704-06
LR-DCPP-04-106704-14
LR-DCPP-05-106705-02
LR-DCPP-06-106706-05
LR-DCPP-06-106706-07
LR-DCPP-06-106706-08
LR-DCPP-28-106728-04
LR-DCPP-28-106728-05
LR-DCPP-28-106728-07A
LR-DCPP-28-107728-04
LR-DCPP-28-107728-05
LR-DCPP-28-107728-07A

The license renewal boundary drawings for the turbine generator associated systems are listed below:

LR-DCPP-22-106722-02
LR-DCPP-22-106722-03
LR-DCPP-22-106722-04
LR-DCPP-22-106722-05
LR-DCPP-22-106722-05A
LR-DCPP-22-106722-06
LR-DCPP-22-107722-02
LR-DCPP-22-107722-03
LR-DCPP-22-107722-04
LR-DCPP-22-107722-05
LR-DCPP-22-107722-06

Formatted: Font color: Blue

Formatted: Font color: Blue

Formatted: Font color: Blue

Formatted: Font color: Blue

2.3.4.1 Turbine Steam Supply System

System Description

The turbine steam supply system conveys the generated steam from the nuclear steam supply system to the turbine generator, turbine driven feedwater pumps, the turbine-driven auxiliary feedwater pump, condenser steam dumps, and the auxiliary steam system. Portions of the turbine steam supply system piping and piping components in the turbine building contain high energy fluids.

Deleted: feed

System Intended Functions

The turbine steam supply system provides heat removal from the RCS for controlled cooldown during normal, accident and post-accident conditions. Portions of the turbine steam supply system provide containment isolation and overpressure protection for the secondary side of the steam generators and the main steam piping. The turbine steam supply system also provides steam as a motive force to support the operation of the turbine-driven auxiliary feedwater pumps. Therefore, the turbine steam supply system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1).

Deleted: portions of

Deleted: are

Portions of the safety-related turbine steam supply system attach to nonsafety-related piping such that the structural failure of the nonsafety-related piping could prevent satisfactory accomplishment of safety-related system functions. Some of the turbine steam supply system in the auxiliary building contains nonsafety-related components that are spatially oriented such that their failure could prevent the satisfactory accomplishment of a safety-related function associated with a safety-related component. High energy portions of turbine steam supply system in the turbine building could prevent the satisfactory accomplishment of a safety-related function associated with certain safety-related cables. These portions of the turbine steam supply system are in scope as nonsafety affecting safety-related components based on the criterion of 10 CFR 54.4(a)(2).

Deleted: Therefore,

Deleted: within the

Deleted: of license renewal

Portions of the turbine steam supply system support ATWS, fire protection, SBO and EQ requirements and are within the scope of license renewal based on the criteria 10 CFR 54.4(a)(3).

FSAR References

Additional details of the turbine steam supply system can be found in FSAR Sections 3.6.1.2, 6.5.2.1.2, 10.2, 10.3, 10.4.4, and 10.4.8.

License Renewal Boundary Drawings

The license renewal boundary drawings for the turbine steam supply system are listed below:

LR-DCPP-04-106704-05
LR-DCPP-04-106704-06
LR-DCPP-04-106704-07
LR-DCPP-04-106704-09
LR-DCPP-04-106704-10
LR-DCPP-04-106704-11
LR-DCPP-04-106704-12
LR-DCPP-04-106704-13
LR-DCPP-04-106704-17
LR-DCPP-04-107704-05
LR-DCPP-04-107704-06
LR-DCPP-04-107704-07
LR-DCPP-04-107704-10
LR-DCPP-04-107704-11
LR-DCPP-04-107704-12
LR-DCPP-04-107704-13

Deleted:

2.3.4.2 Auxiliary Steam System

System Description

The auxiliary steam system consists of two auxiliary boilers, pumps, receivers, tanks, piping, and valves. One auxiliary boiler (0-2) is located in a separate building; the other auxiliary boiler (0-1) is located in a separate room in the Unit 1 ventilation building and is abandoned. The piping and valves associated with the auxiliary steam system are located in the auxiliary boiler enclosure, the turbine building, the auxiliary building, the fuel handling building, and the containment. The system contains piping which penetrates containment and contains the necessary containment isolation valves. The auxiliary steam system piping and piping components in the turbine building contain high energy fluids.

System Intended Functions

Portions of the nonsafety-related auxiliary steam system piping are attached to safety-related containment penetration piping such that the structural failure of the nonsafety-related piping could prevent satisfactory accomplishment of safety-related system functions. Portions of the auxiliary steam system in the auxiliary building and containment contain nonsafety-related components that are spatially oriented such that their failure could prevent the satisfactory accomplishment of a safety-related function associated with a safety-related component. The high energy portions of the auxiliary steam system in the turbine building could prevent the satisfactory accomplishment of a safety-related function associated with certain safety-related cables. These portions of the auxiliary steam system are within the scope of license renewal as nonsafety-related components affecting safety-related components based on the criterion of 10 CFR 54.4(a)(2).

FSAR References

Additional details of the auxiliary steam system are included in FSAR Sections 3.6.1.2 and 9.3.7.1.

License Renewal Boundary Drawings

The license renewal boundary drawings for the auxiliary steam system are listed below:

LR-DCPP-06-106706-04

2.3.4.3 Feedwater System

System Description

The water discharged from the feedwater pumps flows through the single stage of high pressure heaters to the steam generators through four lines penetrating the containment, one line for each steam generator. Flow regulating valves, flow venturis, isolation valves, bypass regulating valves, and a check valve are installed in each line outside the containment. The feedwater system piping and piping components in the turbine building contain high energy fluids.

System Intended Functions

Portions of the safety-related feedwater system attach to nonsafety-related piping such that the structural failure of the nonsafety-related piping could prevent satisfactory accomplishment of safety-related system functions. Portions of the feedwater system in the auxiliary building contain nonsafety-related components that are spatially oriented such that their failure could prevent the satisfactory accomplishment of a safety-related function associated with a safety-related component. The high energy portions of the feedwater system that are in the turbine building could prevent the satisfactory accomplishment of a safety-related function associated with certain safety-related cables. These portions of feedwater system are within the scope of license renewal as nonsafety affecting safety-related components based on the criterion of 10 CFR 54.4(a)(2).

FSAR References

Additional details of the feedwater system are included in FSAR Sections 3.6.1.2 and 10.4.7.

License Renewal Boundary Drawings

The license renewal boundary drawings for the feedwater system are listed below:

LR-DCPP-03-106703-05
LR-DCPP-03-107703-05

2.3.4.4 Condensate System

System Description

The purposes of the condensate system are: (1) to collect the condensate from the exhaust steam of main turbines and feedwater pump turbines and the steam cycle drains in the main condenser hotwell, and (2) to deliver deaerated water from the main condenser hotwells to the suction of the main feedwater pumps. Together with the feedwater system, the feedwater is delivered to the steam generators at the required pressure and temperature. The hotwell may also provide water to the firewater system or the auxiliary feedwater system for long-term cooling.

Major components in the condensate system include the main condenser, condensate demineralizers three half capacity centrifugal condensate pumps and three condensate booster pumps.

The condensate system interfaces with the feedwater system, which is evaluated in Section 2.3.4.3. The condensate system interfaces with the secondary sampling system, which is evaluated in the secondary sampling system in Section 2.3.3.18. The condensate storage tank, which provides makeup and surge capacity to compensate for changes in condensate system inventory, is evaluated in the makeup water system in Section 2.3.3.5.

Portions of the condensate system piping and piping components in the turbine building contain high energy fluids.

System Intended Functions

Portions of the condensate system are located in the auxiliary building and contain nonsafety-related components that are spatially oriented such that their failure could prevent the satisfactory accomplishment of a safety-related function associated with a safety-related component. High energy portions of the condensate system in the turbine building could prevent the satisfactory accomplishment of a safety-related function associated with certain safety-related cables. Portions of the condensate system may be used to provide water for long term cooling. These portions of the condensate system are in scope as nonsafety affecting safety-related components based on the criterion of 10 CFR 54.4(a)(2).

The license renewal boundary drawings for the condensate system are listed below:

LR-DCPP-02-106702-05
LR-DCPP-02-106702-06

LR-DCPP-02-106702-07
LR-DCPP-02-106702-08LR-DCPP-02-106702-12
LR-DCPP-02-106702-14LR-DCPP-02-107702-05
LR-DCPP-02-107702-06
LR-DCPP-02-107702-07
LR-DCPP-02-107702-08LR-DCPP-02-107702-12
LR-DCPP-02-107702-14

Deleted:

Deleted:

Deleted:

Deleted:

3.3.2.1.18 Miscellaneous Systems In-Scope ONLY based on Criterion 10 CFR 54.4(a)(2)

Materials

The materials of construction for the miscellaneous systems in scope ONLY based on Criterion 10 CFR 54.4(a)(2) component types are:

- Copper Alloy (greater than 15 percent Zinc)
- Nickel Alloys

Formatted: Bullets and Numbering

Environment

The miscellaneous systems in scope ONLY based on Criterion 10 CFR 54.4(a)(2) component types are exposed to the following environments:

- Dry Gas
- Lubricating Oil

Formatted: Bullets and Numbering

Aging Effects Requiring Management

The following miscellaneous systems in-scope ONLY based on Criterion 10 CFR 54.4(a)(2) aging effects require management:

- Wall thinning

Formatted: Bullets and Numbering

Aging Management Programs

The following aging management programs manage the aging effects for the miscellaneous systems in scope ONLY based on Criterion 10 CFR 54.4(a)(2) component types:

- Flow-Accelerated Corrosion (B2.1.6)
- Lubricating Oil Analysis (B2.1.23)

Formatted: Bullets and Numbering

3.4.2.1.1 Turbine Steam Supply System

Materials

The materials of construction for the turbine steam supply system component types are:

- Glass
- Nickel Alloys

Formatted: Bullets and Numbering

3.4.2.1.2 Auxiliary Steam System

Materials

The materials of construction for the auxiliary steam system component types are:

- Cast Iron (Gray Cast Iron)

Environment

The auxiliary steam system components are exposed to the following environments:

Formatted: Bullets and Numbering

Deleted: <#>Dry Gas¶

3.4.2.1.4 Condensate System

Environment

The condensate system components are exposed to the following environments:

- Closed Cycle Cooling Water
- Dry Gas

Formatted: Bullets and Numbering

Aging Effects Requiring Management

The following condensate system aging effects require management:

- Cracking

Formatted: Bullets and Numbering

Aging Management Programs

The following aging management programs manage the aging effects for the condensate system component types:

- Closed-Cycle Cooling Water System (B2.1.10)

Formatted: Bullets and Numbering

Table 2.2-1 DCPP Scoping Results

System/Structure	In Scope	Section 2 Scoping Results
Reactor Vessel, Internals, and Reactor Coolant System		
Pressurizer	Yes	2.3.1.3
Reactor coolant, includes: RVLIS and RVRLIS	Yes	2.3.1.2
Reactor core, includes: Nuclear Fuel Control Rod Mechanical SSCs	Yes	2.3.1.5
Reactor vessel and internals	Yes	2.3.1.1
Steam generators	Yes	2.3.1.4
Engineered Safety Features		
Containment HVAC, including: Containment H_2 control	Yes	2.3.2.4
Containment spray	Yes	2.3.2.2
Residual heat removal	Yes	2.3.2.3
Safety injection	Yes	2.3.2.1
Auxiliary Systems		
Auxiliary building HVAC, includes: Main auxiliary building HVAC Miscellaneous auxiliary building HVAC Fuel handling building HVAC	Yes	2.3.3.11
Chemical and volume control	Yes	2.3.3.8
Component cooling water	Yes	2.3.3.4
Compressed air, includes: Backup air and N_2 Compressed breathing air	Yes	2.3.3.7
Control Room HVAC, includes: Plant process computer HVAC	Yes	2.3.3.10
Cranes and fuel handling, includes: Fuel handling cranes, hoists, and monorails Nuclear fuel storage	Yes	2.3.3.1
Diesel generator fuel oil	Yes	2.3.3.13
Diesel generator	Yes	2.3.3.14

System/Structure	In Scope	Section 2 Scoping Results
Fire Protection, includes: Fire Detection Firewater system CO_2 system Halon (Sim/Comp Rooms) system Portable fire extinguishers	Yes	2.3.3.12
Gaseous radwaste	Yes	2.3.3.16
Liquid radwaste	Yes	2.3.3.17
Lube Oil	Yes	2.3.3.15
Makeup water, includes Domestic and drinking water	Yes	2.3.3.5
Miscellaneous HVAC, includes: Turbine Building ASW Pump Room Ventilation Radwaste Storage Building	Yes	2.3.3.9
Miscellaneous systems in scope ONLY for criterion 10 CFR 54.4(a)(2), includes:	Yes	2.3.3.18
Extraction steam and heater drip	-	-
Radiation monitoring (mechanical)	-	-
Sanitary sewage	-	-
Secondary sampling	-	-
Service cooling water	-	-
Solid radwaste	-	-
Turbine generator associated systems	-	-
Nuclear steam supply sampling	Yes	2.3.3.6
Oily water and turbine sump	Yes	2.3.3.19
Saltwater and chlorination, includes: Saltwater system Auxiliary saltwater Chlorination	Yes	2.3.3.3
Spent fuel pool cooling, includes: Spent fuel pool cooling Spent fuel pool purification	Yes	2.3.3.2
Hazardous waste	No	N/A
Laundry facility and decontamination equipment	No	N/A
Nitrogen and hydrogen	No	N/A

System/Structure	In Scope	Section 2 Scoping Results
Steam and Power Conversion System		
Auxiliary feedwater, includes: Long-term cooling water - auxiliary feedwater alternate suction sources	Yes	2.3.4.5
Auxiliary steam	Yes	2.3.4.2
Condensate, includes: Condensate polishing	Yes	2.3.4.4
Feedwater	Yes	2.3.4.3
Turbine steam supply (TSS), includes: TSS –downstream of MSIV TSS –upstream of MSIV TSS –steam generator blowdown	Yes	2.3.4.1
Containments, Structures, and Component Supports		
Auxiliary building	Yes	2.4.3
Containment building	Yes	2.4.1
Control room (located in auxiliary building)	Yes	2.4.2
Discharge structure	Yes	2.4.12
Diesel fuel oil pump vaults and structures	Yes	2.4.7
Earthwork and yard structures	Yes	2.4.11
Fuel handling building	Yes	2.4.9
Intake structure and intake control building	Yes	2.4.10
Outdoor water storage tank foundations and encasements	Yes	2.4.13
Pipeway structure	Yes	2.4.6
Radwaste storage facilities	Yes	2.4.5
Supports	Yes	2.4.14
Turbine building, includes: Administration building CCW heat exchanger room Elevated walkway Emergency diesel generator rooms	Yes	2.4.4
230kV Switchyard, 500kV Switchyard, and electrical foundations and structures	Yes	2.4.8
Independent spent fuel storage installation and cask transfer facility	No	N/A
Auxiliary boiler enclosure	No	N/A

Deleted: Turbine generator associated systems ...

System/Structure	In Scope	Section 2 Scoping Results
Avila gate guardhouse	No	N/A
Avila gate storage building	No	N/A
Bechtel administration trailers	No	N/A
Bio-lab shower / Laboratory facility	No	N/A
Biological laboratory and offices	No	N/A
Blast and paint facility	No	N/A
Boat dock	No	N/A
Boat repair shop	No	N/A
Building, auto, and land services trailer	No	N/A
Building mechanic shop	No	N/A
Chemical storage building	No	N/A
Chlorination and domestic water building (not in use)	No	N/A
Clarifier and make-up pretreatment building	No	N/A
Document Control RMS Building	No	N/A
Document storage facilities	No	N/A
Emergency Operations Facility	No	N/A
Employee assistance program office trailer	No	N/A
Energy Information Center	No	N/A
Engineering services trailer	No	N/A
Environmental monitoring program facilities	No	N/A
Firing range	No	N/A
Fitness for duty buildings	No	N/A
Fitness trailer	No	N/A
Fleet mechanic office	No	N/A
Gas cylinder storage	No	N/A
General construction paint compressor building (not in use)	No	N/A
General construction paint shack / sand blast facility	No	N/A
Hazardous waste facility	No	N/A
Hazardous material office and warehouse	No	N/A
Housekeeping field office	No	N/A
Intake maintenance shop	No	N/A
Intake office/security access building	No	N/A

System/Structure	In Scope	Section 2 Scoping Results
Ionics reverse osmosis facility	No	N/A
Laundry facility	No	N/A
Learning center and maintenance shop	No	N/A
Learning center and simulator	No	N/A
Main warehouse	No	N/A
MATCON express trailer	No	N/A
Meteorological Tower No. 1 and building	No	N/A
Meteorological Tower No. 2 and building	No	N/A
NOS project files	No	N/A
Nuclear Quality Services trailer	No	N/A
Oceanography laboratory	No	N/A
Offsite emergency laboratory	No	N/A
Old Steam Generator Storage Facility	No	N/A
Outage services facilities	No	N/A
Plant compressed air facility	No	N/A
Plant security building and structures	No	N/A
Portable fire pump building	No	N/A
Raw water collection facility and wells at Diablo Creek	No	N/A
Radiation protection trailer	No	N/A
Restroom trailers	No	N/A
Scaffold storage building	No	N/A
Security guard station	No	N/A
Service air pad building	No	N/A
Sewage treatment plant	No	N/A
Site overlook	No	N/A
Storage building - 500kV switchyard	No	N/A
Technical maintenance/Telecom/Medical facility	No	N/A
Telecommunications trailer	No	N/A
Telephone terminal building	No	N/A
Turbine generator equipment warehouse	No	N/A
Unit 2 cold machine shop	No	N/A
Utility Crew / Firewatch / Radwaste field office	No	N/A

System/Structure	In Scope	Section 2 Scoping Results
Vehicle maintenance shop	No	N/A
Vehicle maintenance shop parts office	No	N/A
Vending machine facility	No	N/A
Warehouse A	No	N/A
Warehouse B	No	N/A
Wastewater holding and treatment equipment enclosure	No	N/A
Westinghouse office trailer	No	N/A
Yard Containment Access Facility	No	N/A
Electrical and Instrumentation and Controls		
AMSAC	Yes	N/A
Control rod electrical SSCs	Yes	N/A
Communications	Yes	N/A
Eagle 21	Yes	N/A
Emergency lighting, includes: Emergency AC lighting Emergency DC lighting Battery operated lighting Control room lighting Pipe rack lighting	Yes	N/A
Incore flux mapping	Yes	N/A
Main generator electrical equipment (25kV)	Yes	N/A
Nuclear instrumentation	Yes	N/A
Radiation monitoring	Yes	N/A
Safety parameter display	Yes	N/A
Seismic monitoring, includes: Reactor seismic trip	Yes	N/A
Site emergency and containment evacuation	Yes	N/A
Solid state protection	Yes	N/A
120 VAC	Yes	N/A
125 VDC	Yes	N/A
480V	Yes	N/A
4.16kV	Yes	N/A
12kV	Yes	N/A
230kV	Yes	N/A

System/Structure	In Scope	Section 2 Scoping Results
500kV	Yes	N/A
Auxiliary building control board digital	No	N/A
Boric acid heat trace	No	N/A
Cathodic protection	No	N/A
Digital rod position indication	No	N/A
Loose parts monitoring	No	N/A
Meteorological monitoring	No	N/A
Plant data network	No	N/A
Plant process computer and annunciator	No	N/A
Security	No	N/A
Security UPS	No	N/A
120V general use and normal lighting	No	N/A

Table 2.3.3-18 Miscellaneous Systems In Scope ONLY Based on Criterion 10 CFR 54.4(a)(2)

Component Type	Intended Function
Expansion Joint	Leakage Boundary (spatial)
Heat Exchanger (Air Side Seal Oil Cooler)	Leakage Boundary (spatial)
Heat Exchanger (Gas Dryer Water Gas)	Leakage Boundary (spatial)
Heat Exchanger (Gas Dryer)	Leakage Boundary (spatial)
Heat Exchanger (H2 Side Seal Oil Cooler)	Leakage Boundary (spatial)
Heat Exchanger (Stator Clg O2 Cooler)	Leakage Boundary (spatial)
Orifice	Leakage Boundary (spatial)
Regulators	Leakage Boundary (spatial)
Rupture Disc	Leakage Boundary (spatial)
Thermowell	Leakage Boundary (spatial)
Trap	Leakage Boundary (spatial)

Formatted: Not Highlight

Formatted: Not Highlight

Table 2.3.4-1 Turbine Steam Supply System

Component Type	Intended Function
Expansion Joint	Leakage Boundary (spatial)
Flow Indicator	Leakage Boundary (spatial)
Heat Exchanger (Steam Generator Blowdown)	Leakage Boundary (spatial)
Heat Exchanger (Turbine Bldg)	Leakage Boundary (spatial)
Sight Gauge	Leakage Boundary (spatial)
Strainer	Filter Leakage Boundary (spatial) Pressure Boundary
Turbine	Leakage Boundary (spatial) Pressure Boundary

Deleted: Test Connection ...

Table 2.3.4-2 Auxiliary Steam System

Component Type	Intended Function
Heat Exchanger (CO2 Vaporizer)	Leakage Boundary (spatial)
Heat Exchanger (Reboiler)	Leakage Boundary (spatial)
Heater	Leakage Boundary (spatial)

Table 2.3.4-3 Feedwater System

Component Type	Intended Function
Filter	Leakage Boundary (spatial)
Flow Element	Leakage Boundary (spatial) Pressure Boundary Throttle
Heat Exchanger (Feedwater Heater)	Leakage Boundary (spatial) Structural Integrity (attached)
Orifice	Leakage Boundary (spatial)

Table 2.3.4-4 Condensate System

Component Type	Intended Function
Demineralizer	Leakage Boundary (spatial)
Ejector	Leakage Boundary (spatial)
Filter	Leakage Boundary (spatial)
Flexible Hoses	Leakage Boundary (spatial)
Flow Element	Leakage Boundary (spatial)
Flow Indicator	Leakage Boundary (spatial)
Heat Exchanger (Caustic Dilution Hx - Shell)	Leakage Boundary (spatial)
Heat Exchanger (Caustic Dilution Hx - Tubesheet)	Leakage Boundary (spatial)
Heat Exchanger (Condensate Cooler - Shell)	Leakage Boundary (spatial)
Heat Exchanger (Condensate Cooler - Tubesheet)	Leakage Boundary (spatial)
Heat Exchanger (Feedwater Heater - Head)	Leakage Boundary (spatial)

Table 2.3.4-4 Condensate System (Continued)

Component Type	Intended Function
Heat Exchanger (Feedwater Heater - Shell)	Leakage Boundary (spatial)
Heat Exchanger (Feedwater Heater)	Leakage Boundary (spatial)
Heat Exchanger (Gland Steam Condenser - Head)	Leakage Boundary (spatial)
Heat Exchanger (Gland Steam Condenser - Shell)	Leakage Boundary (spatial)
Heat Exchanger (Heaters Drain Cooler - Head)	Leakage Boundary (spatial)
Heat Exchanger (Heaters Drain Cooler - Shell)	Leakage Boundary (spatial)
Heat Exchanger (Hydrogen Cooler - Head)	Leakage Boundary (spatial)
Heat Exchanger (Hydrogen Cooler - Shell)	Leakage Boundary (spatial)
Heat Exchanger (SJAE Aftercondenser - Head)	Leakage Boundary (spatial)
Heat Exchanger (SJAE Aftercondenser - Shell)	Leakage Boundary (spatial)
Heat Exchanger (SJAE Intercondenser - Head)	Leakage Boundary (spatial)
Heat Exchanger (SJAE Intercondenser - Shell)	Leakage Boundary (spatial)
Heat Exchanger (Stator Coil Cooler - Head)	Leakage Boundary (spatial)
Heat Exchanger (Stator Coil Cooler - Shell)	Leakage Boundary (spatial)
Orifice	Leakage Boundary (spatial)
Pulsation Dampener	Leakage Boundary (spatial)
Strainer	Leakage Boundary (spatial)
Tank	Leakage Boundary (spatial)
Trap	Leakage Boundary (spatial)
Tubing	Leakage Boundary (spatial)

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

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1.80	Stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water	Loss of material due to pitting, crevice, and microbiologically influenced corrosion	Open-Cycle Cooling Water System (B2.1.9)	No	Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22) is credited.

Deleted: Not applicable. DCPP has no in-scope stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water in the emergency diesel generator system, so the applicable NUREG-1801 lines were not used.

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Closure Bolting	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	Bolting Integrity (B2.1.7)	VIII.H-4	3.4.1.22	B
Closure Bolting	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of preload	Bolting Integrity (B2.1.7)	VIII.H-5	3.4.1.22	B
Demineralizer	LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VII.C2-14	3.3.1.47	B
Demineralizer	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Expansion Joint	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Expansion Joint	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-1	3.4.1.16	A
Expansion Joint	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-2	3.4.1.14	A
Filter	LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VII.C2-14	3.3.1.47	B
Filter	LBS	Carbon Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-14	3.4.1.07	B
Filter	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Filter	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-24	3.4.1.25	B
Filter	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Cracking	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-25	3.4.1.23	B

Deleted: , SIA

Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Not Highlight
Formatted: Not Highlight
Formatted: Not Highlight
Formatted Table

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Filter	LBS	Stainless Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-9	3.4.1.19	B
Filter	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Flow Element	LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VII.C2-14	3.3.1.47	B
Flow Element	LBS	Carbon Steel	Dry Gas (Int)	None	None	VIII.I-15	3.4.1.44	A
Flow Element	LBS	Carbon Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-14	3.4.1.07	B
Flow Element	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Flow Element	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Flow Element	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Flow Element	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-24	3.4.1.25	B
Flow Element	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Cracking	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-25	3.4.1.23	B
Flow Element	LBS	Stainless Steel	Dry Gas (Int)	None	None	VIII.I-12	3.4.1.44	A
Flow Element	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A

Formatted Table

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Flow Element	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-1	3.4.1.16	A
Flow Element	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-2	3.4.1.14	A
Flow Element	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Flow Element	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Flow Indicator	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Flow Indicator	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Flow Indicator	LBS	Glass	Plant Indoor Air (Ext)	None	None	VIII.I-5	3.4.1.40	A
Flow Indicator	LBS	Glass	Secondary Water (Int)	None	None	VIII.I-8	3.4.1.40	A
Flow Indicator	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VII.J-15	3.3.1.94	A
Flow Indicator	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Flow Indicator	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-4	3.4.1.16	A

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Flow Indicator	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Flow Indicator	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A
Heat Exchanger (Air Side Seal Oil Cooler)	LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.A-1	3.4.1.24	B
Heat Exchanger (Air Side Seal Oil Cooler)	LBS	Carbon Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-14	3.4.1.07	B
Heat Exchanger (Air Side Seal Oil Cooler)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Air Side Seal Oil Cooler)	LBS	Copper Alloy	Closed Cycle Cooling Water (Ext)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-16	3.4.1.26	D
Heat Exchanger (Air Side Seal Oil Cooler)	LBS	Copper Alloy	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-16	3.4.1.26	D
Heat Exchanger (Air Side Seal Oil Cooler)	LBS	Copper Alloy	Lubricating Oil (Ext)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-3	3.4.1.18	B

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Air Side Seal Oil Cooler)	LBS	Copper Alloy	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-3	3.4.1.18	B
Heat Exchanger (Gas Dryer Water Gas)	LBS	Carbon Steel	Dry Gas (Int)	None	None	VIII.I-15	3.4.1.44	A
Heat Exchanger (Gas Dryer Water Gas)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Gas Dryer Water Gas)	LBS	Carbon Steel	Secondary Water (Ext)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A
Heat Exchanger (Gas Dryer Water Gas)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A
Heat Exchanger (Gas Dryer)	LBS	Carbon Steel	Dry Gas (Int)	None	None	VIII.I-15	3.4.1.44	A
Heat Exchanger (Gas Dryer)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (H2 Side Seal Oil Cooler)	LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.A-1	3.4.1.24	B

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (H2 Side Seal Oil Cooler)	LBS	Carbon Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-14	3.4.1.07	B
Heat Exchanger (H2 Side Seal Oil Cooler)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (H2 Side Seal Oil Cooler)	LBS	Copper Alloy	Closed Cycle Cooling Water (Ext)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-16	3.4.1.26	D
Heat Exchanger (H2 Side Seal Oil Cooler)	LBS	Copper Alloy	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-16	3.4.1.26	D
Heat Exchanger (H2 Side Seal Oil Cooler)	LBS	Copper Alloy	Lubricating Oil (Ext)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-3	3.4.1.18	B
Heat Exchanger (H2 Side Seal Oil Cooler)	LBS	Copper Alloy	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-3	3.4.1.18	B
Heat Exchanger (Stator Clg O2 Cooler)	LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.A-1	3.4.1.24	B

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Stator Clg O2 Cooler)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Stator Clg O2 Cooler)	LBS	Copper Alloy	Closed Cycle Cooling Water (Ext)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-16	3.4.1.26	D
Heat Exchanger (Stator Clg O2 Cooler)	LBS	Copper Alloy	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-16	3.4.1.26	D
Orifice	LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VII.C2-14	3.3.1.47	B
Orifice	LBS	Carbon Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-14	3.4.1.07	B
Orifice	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Orifice	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-24	3.4.1.25	B
Orifice	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Cracking	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-25	3.4.1.23	B
Orifice	LBS	Stainless Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-9	3.4.1.19	B
Orifice	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A

Formatted Table

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Orifice	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-1	3.4.1.16	A
Orifice	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-2	3.4.1.14	A
Orifice	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Orifice	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Piping	LBS	Carbon Steel	Dry Gas (Int)	None	None	VIII.I-15	3.4.1.44	A
Piping	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Piping	LBS	Carbon Steel	Plant Indoor Air (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.B1-7	3.4.1.30	B
Piping	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-7	3.4.1.04	A
Piping	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Piping	LBS	Carbon Steel	Secondary Water (Int)	Wall thinning	Flow-Accelerated Corrosion (B2.1.6)	VIII.E-35	3.4.1.29	B

Formatted Table

Deleted: 40

Formatted Table

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Piping	LBS	Carbon Steel	Steam (Int)	Wall thinning	Flow-Accelerated Corrosion (B2.1.6)	VIII.A-17	3.4.1.29	B
Piping	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-4	3.4.1.02	A
Piping	LBS	Carbon Steel	Steam (Int)	Wall thinning	Flow-Accelerated Corrosion (B2.1.6)	VIII.C-5	3.4.1.29	B
Piping	LBS	Nickel Alloys	Plant Indoor Air (Ext)	None	None	VIII.I-9	3.4.1.41	A
Piping	LBS	Nickel Alloys	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-1	3.4.1.37	E, 4
Piping	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-24	3.4.1.25	B
Piping	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Cracking	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-25	3.4.1.23	B
Piping	LBS	Stainless Steel	Dry Gas (Int)	None	None	VIII.I-12	3.4.1.44	A
Piping	LBS	Stainless Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-9	3.4.1.19	B
Piping	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Piping	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-1	3.4.1.16	A

Formatted Table

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-2	3.4.1.14	A
Piping	LBS, SIA	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-5	3.4.1.14	A
Pump	LBS	Carbon Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-14	3.4.1.07	B
Pump	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Pump	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-7	3.4.1.04	A
Pump	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-24	3.4.1.25	B
Pump	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Cracking	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-25	3.4.1.23	B
Pump	LBS	Stainless Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-9	3.4.1.19	B
Pump	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Regulators	LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VII.C2-14	3.3.1.47	B
Regulators	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Formatted Table

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Rupture Disc	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Rupture Disc	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-7	3.4.1.04	A
Sight Gauge	LBS	Carbon Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-14	3.4.1.07	B
Sight Gauge	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Sight Gauge	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-11	3.4.1.04	A
Sight Gauge	LBS	Glass	Lubricating Oil (Int)	None	None	VIII.I-6	3.4.1.40	A
Sight Gauge	LBS	Glass	Plant Indoor Air (Ext)	None	None	VIII.I-5	3.4.1.40	A
Sight Gauge	LBS	Stainless Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-9	3.4.1.19	B
Sight Gauge	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Sight Gauge	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-4	3.4.1.16	A
Sight Gauge	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-5	3.4.1.14	A

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Strainer	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Strainer	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Strainer	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Tank	LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VII.C2-14	3.3.1.47	B
Tank	LBS	Carbon Steel	Dry Gas (Int)	None	None	VIII.I-15	3.4.1.44	A
Tank	LBS	Carbon Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-14	3.4.1.07	D
Tank	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Tank	LBS	Carbon Steel	Plant Indoor Air (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.B1-7	3.4.1.30	D
Tank	LBS	Carbon Steel	Plant Indoor Air (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.B1-7	3.4.1.30	B

Formatted Table

Formatted Table

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Tank	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-7	3.4.1.04	C
Tank	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	C
Tank	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-24	3.4.1.25	D
Tank	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Cracking	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-25	3.4.1.23	D
Tank	LBS	Stainless Steel	Dry Gas (Int)	None	None	VIII.I-12	3.4.1.44	C
Tank	LBS	Stainless Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-9	3.4.1.19	B
Tank	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	C
Test Connection	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Test Connection	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-7	3.4.1.04	A
Test Connection	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-4	3.4.1.02	A
Thermowell	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-24	3.4.1.25	B
Thermowell	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Cracking	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-25	3.4.1.23	B

Formatted Table

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Thermowell	LBS	Stainless Steel	Dry Gas (Int)	None	None	VIII.I-12	3.4.1.44	A
Thermowell	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Trap	LBS	Carbon Steel	Dry Gas (Int)	None	None	VIII.I-15	3.4.1.44	A
Trap	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Trap	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Trap	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-4	3.4.1.02	A
Trap	LBS	Stainless Steel	Dry Gas (Int)	None	None	VIII.I-12	3.4.1.44	A
Trap	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Trap	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Trap	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Tubing	LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VII.C2-14	3.3.1.47	B
Tubing	LBS	Carbon Steel	Dry Gas (Int)	None	None	VIII.I-15	3.4.1.44	A

Formatted Table

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Tubing	LBS	Carbon Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-14	3.4.1.07	B
Tubing	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Tubing	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Tubing	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Tubing	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-24	3.4.1.25	B
Tubing	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Cracking	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-25	3.4.1.23	B
Tubing	LBS	Stainless Steel	Dry Gas (Int)	None	None	VIII.I-12	3.4.1.44	A
Tubing	LBS	Stainless Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-9	3.4.1.19	B
Tubing	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Tubing	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Tubing	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Tubing	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Tubing	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Valve	LBS	Carbon Steel	Dry Gas (Int)	None	None	VIII.I-15	3.4.1.44	A
Valve	LBS	Carbon Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-14	3.4.1.07	B
Valve	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Valve	LBS	Carbon Steel	Plant Indoor Air (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.B1-7	3.4.1.30	B
Valve	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-7	3.4.1.04	A
Valve	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Valve	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A

Formatted Table

Formatted Table

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-4	3.4.1.02	A
Valve	LBS	Copper Alloy	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-16	3.4.1.26	B
Valve	LBS	Copper Alloy	Dry Gas (Int)	None	None	VIII.I-3	3.4.1.44	A
Valve	LBS	Copper Alloy	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-3	3.4.1.18	B
Valve	LBS	Copper Alloy (> 15% Zinc)	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-16	3.4.1.26	B
Valve	LBS	Copper Alloy (> 15% Zinc)	Closed Cycle Cooling Water (Int)	Loss of material	Selective Leaching of Materials (B2.1.17)	VIII.E-19	3.4.1.35	A
Valve	LBS	Copper Alloy (> 15% Zinc)	Dry Gas (Int)	None	None	VIII.I-3	3.4.1.44	A
Valve	LBS	Copper Alloy (> 15% Zinc)	Plant Indoor Air (Ext)	None	None	VIII.I-2	3.4.1.41	A
Valve	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-24	3.4.1.25	B
Valve	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Cracking	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-25	3.4.1.23	B
Valve	LBS	Stainless Steel	Dry Gas (Int)	None	None	VIII.I-12	3.4.1.44	A
Valve	LBS	Stainless Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.A-9	3.4.1.19	B
Valve	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A

Formatted Table

Formatted Table

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-1	3.4.1.16	A
Valve	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.C-2	3.4.1.14	A
Valve	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Valve	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A

Table 3.4.1 Summary of Aging Management Evaluations in Chapter VIII of NUREG-1801 for Steam and Power Conversion System

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1.19	Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	Yes	Consistent with NUREG-1801 with aging management program exceptions. **The aging management program(s) with exceptions to NUREG-1801 include: Lubricating Oil Analysis (B2.1.23) **See further evaluation in subsection 3.4.2.2.8.

Deleted: Not applicable. DCPP has no in-scope stainless steel components exposed to lube oil in the steam and power conversion systems, so the applicable NUREG-1801 lines were not used.
See further evaluation in Section 3.4.2.2.8.

Table 3.4.1 Summary of Aging Management Evaluations in Chapter VIII of NUREG-1801 for Steam and Power Conversion System (Continued)

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1.23	Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to stress corrosion cracking	Closed-Cycle Cooling Water System (B2.1.10)	No	Consistent with NUREG-1801 with aging management program exceptions. **The aging management program(s) with exceptions to NUREG-1801 include: Closed-Cycle Cooling Water System (B2.1.10)

Deleted: Not applicable. DCPP has no in-scope stainless steel piping, piping components, or piping elements exposed to closed-cycle cooling water >60°C (140°F), so the applicable NUREG-1801 line was not used.

Table 3.4.1 Summary of Aging Management Evaluations in Chapter VIII of NUREG-1801 for Steam and Power Conversion System (Continued)

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1.24	Steel heat exchanger components exposed to closed cycle cooling water	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System (B2.1.10)	No	Consistent with NUREG-1801 with aging management program exceptions. **The aging management program(s) with exceptions to NUREG-1801 include: Closed-Cycle Cooling Water System (B2.1.10)

Deleted: Not applicable. DCPP has no in-scope steel heat exchanger components exposed to closed cycle cooling water in the steam and power conversion systems, so the applicable NUREG-1801 rows were not used.

Table 3.4.2-1 Steam and Power Conversion System – Summary of Aging Management Evaluation – Turbine Steam Supply System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Expansion Joint	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Expansion Joint	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Expansion Joint	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Flow Element	LBS, PB, TH	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Flow Element	LBS, PB, TH	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Flow Element	LBS, PB, TH	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Flow Element	LBS, PB, TH	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Flow Indicator	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Flow Indicator	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-8	3.4.1.04	A

Table 3.4.2-1 Steam and Power Conversion System – Summary of Aging Management Evaluation – Turbine Steam Supply System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Flow Indicator	LBS	Glass	Plant Indoor Air (Ext)	None	None	VIII.I-5	3.4.1.40	A
Flow Indicator	LBS	Glass	Secondary Water (Int)	None	None	VIII.I-8	3.4.1.40	A
Flow Indicator	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Flow Indicator	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-4	3.4.1.16	A
Flow Indicator	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-5	3.4.1.14	A
Heat Exchanger (Sample Cooler)	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Heat Exchanger (Sample Cooler)	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Heat Exchanger (Steam Generator Blowdown)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Steam Generator Blowdown)	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A

Table 3.4.2-1 Steam and Power Conversion System – Summary of Aging Management Evaluation – Turbine Steam Supply System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Turbine Bldg)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	D
Heat Exchanger (Turbine Bldg)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-11	3.4.1.04	C
Heat Exchanger (Turbine Bldg)	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Orifice	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Orifice	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Orifice	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Orifice	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Piping	LBS	Nickel Alloys	Plant Indoor Air (Ext)	None	None	VIII.I-9	3.4.1.41	A
Piping	LBS	Nickel Alloys	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-1	3.4.1.37	E, 4
Piping	LBS	Stainless Steel	Plant Indoor Air (Int)	None	None	None	None	G

Table 3.4.2-1 Steam and Power Conversion System – Summary of Aging Management Evaluation – Turbine Steam Supply System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Piping	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Sight Gauge	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Sight Gauge	LBS	Carbon Steel	Sodium Hydroxide (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	None	None	G
Sight Gauge	LBS	Carbon Steel	Sulfuric Acid (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	None	None	G
Sight Gauge	LBS	Glass	Plant Indoor Air (Ext)	None	None	VIII.I-5	3.4.1.40	A
Sight Gauge	LBS	Glass	Sodium Hydroxide (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	None	None	G
Sight Gauge	LBS	Glass	Sulfuric Acid (Int)	None	None	None	None	G
Strainer	FIL, LBS, PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Table 3.4.2-1 Steam and Power Conversion System – Summary of Aging Management Evaluation – Turbine Steam Supply System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Strainer	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Tank	LBS	Carbon Steel	Plant Indoor Air (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.B1-7	3.4.1.30	D
Tank	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Trap	LBS	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-8	3.4.1.28	B
Trap	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Trap	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Trap	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Trap	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Turbine	LBS, PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Deleted: Test Connection ...

Table 3.4.2-1 Steam and Power Conversion System – Summary of Aging Management Evaluation – Turbine Steam Supply System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Turbine	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	C
Valve	LBS, PB, SIA	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-8	3.4.1.28	B
Valve	LBS, PB	Carbon Steel	Dry Gas (Int)	None	None	VIII.I-15	3.4.1.44	A
Valve	LBS	Copper Alloy	Plant Indoor Air (Ext)	None	None	VIII.I-2	3.4.1.41	A
Valve	LBS	Copper Alloy	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-5	3.4.1.15	A
Valve	LBS	Stainless Steel	Dry Gas (Int)	None	None	VIII.I-12	3.4.1.44	A
Valve	LBS	Stainless Steel	Plant Indoor Air (Int)	None	None	None	None	G
Valve	LBS, PB, SIA	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Valve	LBS, PB, SIA	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4

Table 3.4.2-2 Steam and Power Conversion System – Summary of Aging Management Evaluation – Auxiliary Steam System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Closure Bolting	LBS	Stainless Steel	Plant Indoor Air (Ext)	Loss of preload	Bolting Integrity (B2.1.7)	None	None	H, 1
Heat Exchanger (Aux Steam Drain Rec Vent Cond)	LBS, SIA, SS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.G-5	3.4.1.24	B
Heat Exchanger (CO2 Vaporizer)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (CO2 Vaporizer)	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-8	3.4.1.37	E, 6
Heat Exchanger (Reboiler)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Reboiler)	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-8	3.4.1.37	E, 6
Heater	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Formatted: Not Highlight

Deleted: VII.F2-9

Deleted: 3.3.1.48

Deleted: Heat Exchanger (Aux Steam Drain Rec Vent Cond) ...

Table 3.4.2-2 Steam and Power Conversion System – Summary of Aging Management Evaluation – Auxiliary Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heater	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-8	3.4.1.37	E, 6
Piping	LBS, SIA	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-8	3.4.1.28	B
Piping	LBS, SIA	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-11	3.4.1.04	A
Piping	LBS, SIA	Carbon Steel	Secondary Water (Int)	Wall thinning	Flow-Accelerated Corrosion (B2.1.6)	VIII.G-39	3.4.1.29	B
Piping	LBS	Stainless Steel	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.H2-18	3.3.1.80	E, 5
Piping	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-4	3.4.1.16	A
Pump	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.G-38	3.4.1.04	A
Strainer	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-8	3.4.1.37	E, 6
Test Connection	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-8	3.4.1.37	E, 6
Valve	LBS	Cast Iron (Gray Cast Iron)	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	None	None	G

Deleted: Piping ...

Formatted: Not Highlight

Deleted: VIII.G-30

Formatted: Not Highlight

Deleted: 3.4.1.32

Deleted: E, 1

Deleted: Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)

Deleted: Piping ...

Table 3.4.2-2 Steam and Power Conversion System – Summary of Aging Management Evaluation – Auxiliary Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	LBS	Cast Iron (Gray Cast Iron)	Secondary Water (Int)	Loss of material	Selective Leaching of Materials (B2.1.17)	VIII.G-26	3.4.1.36	A
Valve	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-4	3.4.1.16	A

Deleted: Valve

Notes for Table 3.4.2-2:

Standard Notes:

G Environment not in NUREG-1801 for this component and material.

H Aging effect not in NUREG-1801 for this component, material and environment combination.

Plant Specific Notes:

1 The Loss of Preload aging effect is not identified in NUREG-1801 for this component, material, and environment combination. Loss of preload is managed by the Bolting Integrity (B2.1.7) AMP.

Deleted: D . Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.¶

Deleted: Component is abandoned-in-place; thus the Water Chemistry aging management program does not apply

Table 3.4.2-3 Steam and Power Conversion System – Summary of Aging Management Evaluation – Feedwater System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Filter	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Filter	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-8	3.4.1.04	A
Filter	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Filter	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-4	3.4.1.16	A
Filter	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-5	3.4.1.14	A
Flow Element	LBS, PB, TH	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Flow Element	LBS, PB, TH	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-8	3.4.1.04	A
Flow Element	LBS, PB, TH	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-5	3.4.1.14	A
Heat Exchanger (Feedwater Heater)	LBS, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Table 3.4.2-3 Steam and Power Conversion System – Summary of Aging Management Evaluation – Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Feedwater Heater)	LBS, SIA	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-8	3.4.1.04	A
Heat Exchanger (Sample Cooler)	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.G-2	3.4.1.25	B
Heat Exchanger (Sample Cooler)	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Orifice	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Orifice	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-4	3.4.1.16	A
Orifice	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-5	3.4.1.14	A
Piping	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Piping	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-4	3.4.1.16	A
Piping	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-5	3.4.1.14	A

Table 3.4.2-3 Steam and Power Conversion System – Summary of Aging Management Evaluation – Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Pump	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Pump	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-8	3.4.1.04	A
Pump	LBS, SIA	Stainless Steel Cast Austenitic	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Pump	LBS, SIA	Stainless Steel Cast Austenitic	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-4	3.4.1.16	A
Pump	LBS, SIA	Stainless Steel Cast Austenitic	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-5	3.4.1.14	A
Valve	LBS, PB	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Valve	LBS, PB	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-4	3.4.1.16	A
Valve	LBS, PB	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.D1-5	3.4.1.14	A

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Closure Bolting	LBS	Stainless Steel	Plant Indoor Air (Ext)	Loss of preload	Bolting Integrity (B2.1.7)	None	None	H, 1
Demineralizer	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Demineralizer	LBS	Carbon Steel	Plant Indoor Air (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.G-34	3.4.1.30	D
Demineralizer	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Ejector	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Ejector	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Ejector	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Ejector	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Ejector	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A
Filter	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Filter	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Filter	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Filter	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Filter	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A
Flexible Hoses	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Flexible Hoses	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Flexible Hoses	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A
Flow Element	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Flow Element	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Flow Element	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Flow Element	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Flow Element	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A
Flow Indicator	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Flow Indicator	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Flow Indicator	LBS	Glass	Plant Indoor Air (Ext)	None	None	VIII.I-5	3.4.1.40	A
Flow Indicator	LBS	Glass	Secondary Water (Int)	None	None	VIII.I-8	3.4.1.40	A
Flow Indicator	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Flow Indicator	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Flow Indicator	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A
Heat Exchanger (Caustic Dilution Hx - Shell)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Caustic Dilution Hx - Shell)	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Heat Exchanger (Caustic Dilution Hx - Tubesheet)	LBS	Copper Alloy	Secondary Water (Ext)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-5	3.4.1.15	C
Heat Exchanger (Caustic Dilution Hx - Tubesheet)	LBS	Copper Alloy	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-5	3.4.1.15	C
Heat Exchanger (Condensate Cooler - Shell)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Condensate Cooler - Shell)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A
Heat Exchanger (Feedwater Heater - Head)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Feedwater Heater - Head)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A
Heat Exchanger (Feedwater Heater - Shell)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Feedwater Heater - Shell)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A
Heat Exchanger (Feedwater Heater - Shell)	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Heat Exchanger (Gland Steam Condenser - Head)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Gland Steam Condenser - Head)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Gland Steam Condenser - Shell)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Gland Steam Condenser - Shell)	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Heat Exchanger (Heaters Drain Cooler - Head)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Heaters Drain Cooler - Head)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A
Heat Exchanger (Heaters Drain Cooler - Shell)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Heaters Drain Cooler - Shell)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A
Heat Exchanger (Hydrogen Cooler - Head)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Hydrogen Cooler - Head)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A
Heat Exchanger (Hydrogen Cooler - Shell)	LBS	Carbon Steel	Dry Gas (Int)	None	None	VIII.I-15	3.4.1.44	A
Heat Exchanger (Hydrogen Cooler - Shell)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Main Condenser)	PB, SIA	Carbon Steel	Secondary Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.E-37	3.4.1.03	E, 2
Heat Exchanger (Main Condenser)	PB, SIA	Carbon Steel	Steam (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.A-16	3.4.1.02	E, 2
Heat Exchanger (SJAE Aftercondenser - Head)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Deleted: 1

Deleted: 1

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (SJAE Aftercondenser - Head)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A
Heat Exchanger (SJAE Aftercondenser - Shell)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (SJAE Aftercondenser - Shell)	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Heat Exchanger (SJAE Intercondenser - Head)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (SJAE Intercondenser - Head)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A
Heat Exchanger (SJAE Intercondenser - Shell)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (SJAE Intercondenser - Shell)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A
Heat Exchanger (Stator Coil Cooler - Head)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Heat Exchanger (Stator Coil Cooler - Head)	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-37	3.4.1.03	A
Heat Exchanger (Stator Coil Cooler - Shell)	LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VIII.E-5	3.4.1.24	B
Heat Exchanger (Stator Coil Cooler - Shell)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Orifice	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Orifice	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Orifice	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Orifice	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Orifice	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A
Piping	LBS	Carbon Steel	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.G-36	3.4.1.08	E, 3
Piping	LBS, PB	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Piping	LBS	Carbon Steel	Secondary Water (Int)	Wall thinning	Flow-Accelerated Corrosion (B2.1.6)	VIII.E-35	3.4.1.29	B
Piping	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Piping	LBS	Carbon Steel	Steam (Int)	Wall thinning	Flow-Accelerated Corrosion (B2.1.6)	VIII.A-17	3.4.1.29	B
Piping	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Piping	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Piping	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A

Deleted: 2

Formatted: Tab stops: 0.65", Left

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Piping	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Pulsation Dampener	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Pulsation Dampener	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Pulsation Dampener	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A
Pump	LBS	Carbon Steel	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.G-36	3.4.1.08	E, 3
Pump	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Pump	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Pump	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A

Formatted: Tab stops: 0.69", Left

Deleted: 2

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Sight Gauge	LBS	Copper Alloy	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.E-18	3.4.1.32	E, 3
Strainer	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Strainer	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Tank	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Tank	LBS	Carbon Steel	Plant Indoor Air (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.G-34	3.4.1.30	D
Tank	LBS	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Trap	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Trap	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Trap	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A

Deleted: 2

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Trap	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Trap	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Tubing	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Tubing	LBS	Stainless Steel	Secondary Water (Ext)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Tubing	LBS	Stainless Steel	Secondary Water (Ext)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A
Tubing	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Tubing	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A
Tubing	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4
Tubing	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4
Valve	LBS, PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	LBS	Carbon Steel	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.G-36	3.4.1.08	E, 3
Valve	LBS	Carbon Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Valve	LBS, PB	Cast Iron	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Valve	LBS, PB	Cast Iron	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-34	3.4.1.04	A
Valve	LBS	Cast Iron	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-16	3.4.1.02	A
Valve	LBS, PB	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Valve	LBS, PB	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Valve	LBS	Stainless Steel	Secondary Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-30	3.4.1.14	A
Valve	LBS	Stainless Steel	Steam (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-10	3.4.1.39	E, 4

Deleted: 2

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	LBS	Stainless Steel	Steam (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.A-12	3.4.1.37	E, 4

Notes for Table 3.4.2-4:

Standard Notes:

H Aging effect not in NUREG-1801 for this component, material and environment combination.

Plant Specific Notes:

1 The Loss of Preload aging effect is not identified in NUREG-1801 for this component, material, and environment combination. Loss of preload is managed by the Bolting Integrity (B2.1.7) AMP.

3 The in-scope condensate system components which may have a raw water environment are abandoned-in-place. Thus, the Open-Cycle Cooling Water System aging management program does not apply.

4 The Water Chemistry Program (B2.1.2) and the One-Time Inspection Program (B2.1.16) manages loss of material due to pitting and crevice corrosion and cracking due to stress corrosion cracking. The One-Time Inspection Program (B2.1.16) includes selected components at susceptible locations.

B2.1.10 Closed-Cycle Cooling Water System

Program Description

The closed-cycle cooling water (CCCW) system program manages loss of material, cracking and reduction of heat transfer for components in the closed-cycle cooling water systems. The program provides for: (1) preventive measures to minimize corrosion including maintenance of corrosion inhibitor, pH buffering agent, and biocide concentrations, and (2) periodic system and component performance testing and inspection. Preventive measures include the monitoring and control of corrosion inhibitors and other chemical parameters, such as pH, in accordance with the guidelines of EPRI TR-107396, Revision 1 (EPRI 1007820). Periodic inspection and testing to confirm function and monitor corrosion is performed in accordance with EPRI TR-107396, Revision 1 (EPRI 1007820), and industry and plant operating experience.

DCPP has four systems within the scope of license renewal that meet the definition for CCCW systems in Generic Letter 89-13 and portions of additional systems (heat exchangers or coolers) that are serviced directly by these systems. These CCCW systems are not subject to significant sources of contamination. The water chemistry is controlled in these systems and heat is not directly rejected to a heat sink.

The CCCW systems in License Renewal scope are:

- component cooling water (CCW) system
- service cooling water (SCW) system
- diesel engine jacket cooling water (DECW) system, a subsystem of the diesel generator system
- auxiliary building HVAC system

The program maintains water chemistry within the parameter limits specified in plant procedures and consistent with those in EPRI TR-107396, Revision 1 (EPRI 1007820), in order to minimize corrosion and microbiological growth. The chemicals added to the CCW and SCW systems are potassium molybdate (iron and aluminum corrosion inhibitor), potassium nitrite (iron corrosion inhibitor), tolyltriazole (TTA - a copper corrosion inhibitor), potassium tetra borate (buffering), potassium hydroxide (pH control), glutaraldehyde (biocide) and isothiazoline (biocide). The chemicals added to the DECW system are potassium dichromate and potassium hydroxide (corrosion inhibitors). The cooling water system associated with the auxiliary building HVAC system is maintained as a sealed pure water system based on potable water, without additives.

The CCCW system program periodically monitors system chemistry to verify it is being maintained in accordance with the guidelines of EPRI TR-107396, Revision 1 (EPRI 1007820), with stated exceptions, to minimize corrosion and SCC. In addition, nonchemistry testing and inspection techniques consistent with EPRI TR-107396, Revision 1 (EPRI 1007820), are used to confirm the effectiveness of the program.

The CCW pumps are periodically tested to verify pump performance. Nondestructive examinations are used to verify that the pressure boundary intended function of the CCW heat exchangers is maintained. Periodic performance testing of the CCW heat exchangers is part of the open-cycle cooling water system program (B2.1.9). Diesel engine performance parameters are monitored through periodic surveillance tests. These tests are used to monitor the performance of the DECW system components. Inspections are performed periodically on the in-scope DECW components.

The SCW system, stator cooling water system, and the auxiliary building HVAC system chilled water systems are within the scope of license renewal per 10 CFR 54.4(a)(2) for spatial interaction concerns only. Therefore, the only component intended function applicable to these systems is (a)(2) leakage boundary (spatial). The periodic sampling and maintenance of system chemistry within specified limits are adequate to manage aging before the loss of this intended function.

Pacific Gas and Electric Company

77 Beale Street
San Francisco, CA 94106
415/972-7000
TWX 910-372-6587

James D. Shiffer
Vice President
Nuclear Power Generation

January 26, 1990

PG&E Letter DCL 90-027

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

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Response to Generic Letter 89-13,
"Service Water System Problems Affecting Safety-Related Equipment"

Gentlemen:

This letter provides PG&E's response to Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," which requested information regarding the establishment of programs to implement the GL 89-13 recommendations, and the schedules for implementing those programs. PG&E's response to GL 89-13 is provided In the Enclosure.

Kindly acknowledge receipt of this material on the enclosed Copy of this letter and return it in the enclosed addressed envelope.

Subscribed to in San Francisco, California this 26th day of January 1990.

Respectfully submitted,
Pacific Gas and Electric Company

By: /s/
J. D. Shiffer
Vice President
Nuclear Power Generation

Howard V. Golub
Richard F. Locke
Attorneys for Pacific
Gas and Electric Company

By /s/
Richard F. Locke

Subscribed and sworn to before me this
26th day of January 1990

/s/
Mildred J. Williams, Notary Public
for the City and County of San Francisco
State of California

My commission expires August 7, 1993.

cc: A. P. Hodgdon
J. B. Martin
M. M. Mendonca
P. P. Narbut
H. Rood

CPUC
Diablo Distribution

Enclosure

3037S/007K/ALN/2232

bcc: RCBueno
DHOatley

3037S/0077K

ENCLOSURE

RESPONSE TO GENERIC LETTER 89-13, "SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT"

This Enclosure provides PG&E's response to the five recommendations of Generic Letter (GL) 89-13. These recommendations are identified below, along with PG&E's planned actions to implement the recommendations and the schedules specific to each recommendation.

1. For open-cycle service water systems, implement and maintain an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling.

Enclosure 1 of GL 89-13 includes guidance regarding the scope and implementation of an acceptable program for surveillance and control to reduce fouling of the auxiliary saltwater (ASW) system. PG&E's surveillance and control program will be consistent with the intent of the guidance described in GL 89-13 and its Enclosure 1 for facilities with a marine water source, specifically surveillance technique A and control techniques B and C.

> Surveillance Technique A: The intake structure should be visually inspected, once per refueling cycle, for macroscopic biological fouling organisms (for example, blue mussels at marine plants, American oysters at estuarine plants, and Asiatic clams at freshwater plants), sediment, and corrosion. Inspections should be performed either by scuba divers or by dewatering the intake structure or by other comparable methods. Any fouling accumulations should be removed.

The Diablo Canyon Power Plant (DCPP) ASW system intake structure is designed to permit isolation and dewatering of the pump bays. In accordance with the GL 89-13 recommended surveillance technique A, PG&E will develop a program to visually inspect the ASW intake structure during refueling outages, including the pump bays and screens. This program will include inspection for macroscopic biological fouling, sediment, and corrosion, as well as actions to be taken for evaluation and disposition if any of these are identified.

> Control Technique B: The service water system should be continuously (for example, during spawning) chlorinated (or equally effectively treated with another biocide) whenever the potential for a macroscopic biological fouling species exists (for example, blue mussels at marine plants, American oysters at estuarine plants, and Asiatic clams at freshwater plants). Chlorination or equally effective treatment is included for freshwater plants without clams because it can help prevent microbiologically influenced corrosion. However, the chlorination (or equally effective) treatment need not be as stringent for plants where the

potential for macroscopic biological fouling species does not exist compared to those plants where it does. Precautions should be taken to obey Federal, State, and local environmental regulations regarding the use of biocides.

With respect to GL 89-13 control technique B, regarding treatment of macroscopic biofouling, GL 89-13 recommends continuous chlorination of the system. In accordance with the DCPP National Pollutant Discharge Elimination System Permit, the ASW system is chlorinated up to three (3) times a week for a maximum period of one half hour. In addition, periodic demusseling heat treatments have been performed on the ASW system when the main circulating water system is demusseled in accordance with DCPP Operating Procedure E-4:V, "Circulating Water System - Demusseling the Saltwater System.' Alternate methods of biofouling control are currently under investigation by the DCPP Biofouling Control Task Force. These include methods of demusseling the ASW system separately from demusseling of the main circulating water system, and alternate chemical biofouling control methods.

Control Technique C: Redundant and infrequently used cooling loops should be flushed and flow tested periodically at the maximum design flow to ensure that they are not fouled or clogged. Other components in the service water system should be tested on a regular schedule to ensure that they are not fouled or clogged. Service water cooling loops should be filled with chlorinated or equivalently treated water before layup. Systems that use raw service water as a source, such as some fire protection systems, should also be chlorinated or equally effectively treated before layup to help prevent microbiologically influenced corrosion. Precautions should be taken to obey Federal, State, and local environmental regulations regarding the use of biocides.

With respect to GL 89-13 control technique C regarding flushing and flow testing, DCPP Surveillance Test Procedure (STP) M-26, "ASW System Performance Monitoring," is performed to flow test the ASW system on a monthly basis to verify design flow capability. This monthly STP ensures that the ASW cooling loops are flushed and flow tested at operating flow, and that no significant fouling or clogging exists in the system. Additionally, the component cooling water (CCW) heat exchangers have pressure differential (dP) indication in the control room, which alarms at a set dP limit to alert the operators that heat exchanger cleaning is required. Upon receipt of such an alarm, work to clean the heat exchanger is initiated in accordance with Annunciator Response Procedure PK-01-01, "ASW SYS HS DELTA P/HDR PRESS." PG&E currently does not use chlorinated water during layup of the ASW system. At the present time, there is no indication that this has resulted in any additional

ASW system biofouling; however, PG&E, as part of the Biofouling Task Force, will investigate the desirability of using chemical treatment and other methods during ASH system layup to control any potential biofouling.

The procedures to implement GL 89-13 techniques B and C are currently in place at DCPP. The procedure to implement GL 89-13 technique A will be established for use prior to startup following the DCPP Unit 1 fourth refueling outage (1R4), the first refueling outage at DCPP beginning nine months after the date of GL 89-13 issuance (July 18, 1989). Preliminary inspections will be performed during the Unit 2 third refueling outage (2R3) currently scheduled to being in March, 1990, as a part of the maintenance work planned for that outage. The full surveillance and control program will be implemented for Unit 1 during 1R4, currently scheduled to begin May 1, 1991, and for Unit 2 during the Unit 2 fourth refueling outage (2R4), currently scheduled to begin December, 1991.

2. Conduct a test program to verify the heat transfer capability of all safety-related heat exchangers cooled by service water. The total test program should consist of an initial test program and a periodic retest program. Both the initial test program and the periodic retest program should include heat exchangers connected to or cooled by one or more open-cycle systems as defined above. Operating experience and studies indicate that closed-cycle service water systems, such as component cooling water systems, have the potential for significant fouling as a consequence of aging-related in-leakage and erosion or corrosion. The need for testing of closed-cycle system heat exchangers has not been considered necessary because of the assumed high quality of existing chemistry control programs. If the adequacy of these chemistry control programs cannot be confirmed over the total operating history of the plant or if during the conduct of the total testing program any unexplained downward trend in heat exchanger performance is identified that cannot be remedied by maintenance of an open-cycle system, it may be necessary to selectively extend the test program and the routine inspection and maintenance program addressed in Action III, below, to the attached closed-cycle systems.

   A program acceptable to the NRC for heat exchanger testing is described in "Program for Testing Heat Transfer Capability" (Enclosure 2). It should be noted that Enclosure 2 is provided as guidance for an acceptable program. An equally effective program to ensure satisfaction of the heat removal requirements of the service water system would also be acceptable.

> An example of an alternative action that would be acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing for degraded performance of the heat exchanger.

PG&E believes that the DCPP closed-cycle, safety-related heat exchangers meet the GL 89-13 exclusion criteria, and that inclusion of these in the test program is therefore not necessary. The bases for this conclusion are: the heat exchangers do not reject heat directly to the ultimate heat sink; the water in the closed-cycle systems is and always has had a corrosion inhibitor; and procedures are in place which ensure that the closed-cycle water chemistry is well-controlled. Additionally, the closed-cycle CCW system design basis specifies water pressure higher than the salt water system with which it interfaces, the water has not been subjected to significant sources of inleakage contamination, and operating history data show that the water quality has remained stable.

There are a total of four open-cycle, safety-related CCW heat exchangers at DCPP. PG&E will develop and conduct a one-time heat exchanger performance test to confirm the baseline heat transfer capability of these heat exchangers. Since it is not feasible to test these heat exchangers at their design heat removal rate (normal heat loads are on the order of 10 to 20 percent of design basis heat loads), a test using high-accuracy temporary instrumentation will be implemented. However, a study performed by PG&E to determine the sensitivity of the fouling factor calculation for design basis loads using data obtained at normal heat loads shows that a one degree error in temperature measurement could result in a greater than 30 percent deviation for the calculated fouling factor. Therefore, phenomena such as thermal stratification in the CCW system heat exchanger outlet piping could introduce significant uncertainties in the test results. Small errors in ASW flow measurement also would introduce additional uncertainties. PG&E therefore cannot commit that these test results will be conclusive. However, the ASW system monitoring program as described below is an alternative method which will ensure that the ASW system operates within its design basis.

To ensure that the system remains capable of maintaining design basis requirements, PG&E intends to implement an alternative monitoring program which combines flow testing, trending, inspection, and frequent preventive maintenance as permitted by GL 89-13. As noted in PG&E's response to recommendation #1 above, the CCW heat exchanger dP is monitored, and tubesheet cleaning and inspection is performed when the dP reaches a predetermined setpoint. During refueling outages, the heat exchanger waterbox coatings are inspected and the tubes are mechanically cleaned in accordance with the DCPP preventive maintenance program. Demusseling and chlorination activities are performed to prevent heat exchanger performance degradation due to biofouling. Fluid temperatures in the heat exchanger are low enough such that scaling is not a concern. Also, the ASW system is tested monthly per SIP M-26 to ensure that system flow rates meet the design basis requirements.

The one-time heat exchanger thermal performance test will be completed during 1R4 and 2R4 respectively. The alternative monitoring program will also be fully in place by the end of 1R4 and 2R4 respectively.

3. Ensure by establishing a routine inspection and maintenance program for open-cycle service water system piping and components that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of the safety-related systems supplied by service water. The maintenance program should have at least the following purposes:

   A. To remove excessive accumulations of biofouling agents, corrosion products, and silt;

   B. To repair defective protective coatings and corroded service water system piping and components that could adversely affect performance of their intended safety functions.

   A description of the program and the results of these maintenance inspections should be documented.

As discussed above, in accordance with the DCPP preventive maintenance program, the CCW heat exchanger tubing is cleaned and the waterboxes are inspected every refueling outage. Additionally, the CCW heat exchangers are cathodically protected and the ASW system piping is lined internally and externally.

During the upcoming 2R3 refueling outage, PG&E will inspect the dewatered ASW pump bays concurrently with ASW pump maintenance, and remove biofouling and silting as appropriate. Limited ASW system piping inspections will be conducted for 2R3, with more extensive piping inspections conducted during 1R4 and 2R4. PG&E is currently evaluating state-of-the-art methods for performing pipe lining inspections and repairs. An inspection program for the ASW system expansion joints is being implemented. Also, as described above, PG&E will develop a program to inspect the ASW pump bays during refueling outages. Procedures to establish a routine inspection and maintenance program for the ASW system to ensure that corrosion, erosion, protective coating failure, silting, and biofouling do not impair the ASW system design basis function will be established by 1R4 and 2R4. The appropriate interval for the performance of these inspections will be determined based on the 1R4 and 2R4 observations. The inspection program will provide for removal of such accumulations, and for repair of degraded ASW components as required.

4. Confirm that the service water system will perform its intended function in accordance with the licensing basis for the plant. Reconstitution of the design basis of the system is not intended. This confirmation should include a review of the ability to perform required safety functions in the

event of failure of a single active component. To ensure that the as-built system is in accordance with the appropriate license basis documentation, this confirmation should include recent (within the past 2 years) system walkdown inspections.

As described in a PG&E Letter to the NRC (DCL-89-099, dated April 19, 1989), PG&E has instituted a Design Basis Document (DBD) Enhancement Program. The purpose of this program is, in part, to develop comprehensive Design Criteria Memoranda (DCMs) for DCPP safety-related systems, and other selected systems, and is also designed to independently identify and resolve any operability concerns. The ASW and CCW system DCMs are currently in the process of being prepared, reviewed and verified. Once complete, these DCMs will confirm the capability of the ASW and CCW system to perform required safety functions in the event of a single active failure, and ensure that the as-built systems are in accordance with applicable licensing basis documentation. In addition, as required by DCPP Nuclear Plant Administrative Procedure A-350, "System Engineering Program," the System Engineer and the System Design Engineer meet quarterly at DCPP to discuss system operation issues and conduct system walkdowns. A quarterly report is prepared based on this meeting to discuss the status of open items concerning each system and action plans for problem resolution.

The ASW and CCW system DCMs will be complete by the end of 1R4, and any unit-specific walkdowns will be complete by the end of 1R4 and 2R4, respectively.

5. Confirm that maintenance practices, operating and emergency procedures, and training that involves the service water system are adequate to ensure that safety-related equipment cooled by the service water system will function as intended and that operators of this equipment will perform effectively. This confirmation should include recent (within the past 2 years) reviews of practices, procedures, and training modules. The intent of this action is to reduce human errors in the operation, repair, and maintenance of the service water system.

The DBD Enhancement Program described above requires a review of the applicable surveillance and/or maintenance testing required to assure that the safety-related equipment in the system under review meets its design basis requirements. The DBD Enhancement Program also reviews system operability requirements, including instrument monitoring and setpoints, to assure that requirements and commitments that could affect safety are maintained.

PG&E will review the ASW and CCW system maintenance, operation, emergency procedures, as well as the associated training programs, to assure that open

and closed-cycle service water systems will function as intended and that operators of these systems will perform effectively. These reviews will be completed prior to plant startup following 1R4.

Pacific Gas and Electric Company

77 Beale Street
San Francisco, CA 94106
415/973-4684
TWX 910-372-6587

James D. Shiffer
Senior Vice President and
General Manager
Nuclear Power Generation

June 28, 1990

PG&E Letter No. DCL-90-166

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

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Response to Generic Letter 90-04, Status of Implementation of Generic Safety Issues (GSIs)

Gentlemen:

Generic Letter 90-04, "Request for Information on the Status of Licensee Implementation of Generic Safety Issues Resolved with Imposition of Requirements or Corrective Actions," dated April 25, 1990, requested that PG&E perform a review and report on the status of implementation of generic safety issues (GSIs). The enclosure provides the implementation status of each GSI for Diablo Canyon Units 1 and 2, references to documentation, and comments, as required, for clarification.

Kindly acknowledge receipt of this material on the enclosed copy of this letter and return it in the enclosed addressed envelope.

Sincerely,
/s/
J. D. Shiffer

cc: A. P. Hodgdon
J. B. Martin
P. P. Narbut
S. A. Richards
H. Rood
CPUC
Diablo Distribution

Enclosure

3197S/0084K/DY/2232

ENCLOSURE

STATUS OF IMPLEMENTATION OF GENERIC SAFETY ISSUES (GSIs)
FOR DIABLO CANYON UNITS 1 AND 2

FACILITY NAME: Diablo Canyon Power Plant Unit 1
DOCKET NO.: 50-275. OL-DPR-80
LICENSEE: Pacific Gas and Electric Company

STATUS OF LICENSEE IMPLEMENTATION OF GENERIC SAFETY ISSUES

RESOLVED WITH IMPOSITION OF REQUIREMENTS OR CORRECTIVE ACTIONS

GSI/(MPA No)	TITLE	APPLICABILITY	STATUS*	COMMENTS
40 (B065)	Safety Concerns Associated With Pipe Breaks In The BWR Scram System	All BWRs	NA	
41 (B058)	BWR Scram Discharge Volume Systems	All BWRs	NA	
43 (B107)	Reliability Of Air Systems	All Plants	C	PG&E letters DCL-89-041, dated Feb. 21, 1989, and DCL-89-154, dated June 6, 1989, provided PG&E's response to Generic Letter 88-14. The letter provided PG&E's actions and schedule to implement the GL 88-14 recommendations. NRC letter dated June 12, 1989, provided acceptance of PG&E's actions regarding GL 88-14. GL 88-14 actions are completed, however, PG&E is continuing an effort to identify air system improvements for enhanced system performance. (Same status for Unit 2.)
51 (L913)	Improving the Reliability of Open-Cycle Service Water Systems	All Plants	I 12/91	PG&E letter DCL-90-027, dated Jan. 26, 1990, provided PG&E's plans and schedules regarding the establishment of programs to implement GL 89-13 recommendations. The commitments are being completed consistent with the schedule provided in DCL-90-027 with expected completion of the Unit 1-only actions during the 4th refueling outage of Unit 1 (May 1991) and expected completion of common Units 1 and 2 actions during the 4th refueling outage of Unit 2 (December 1991). (Same status for Unit 2.)
67.3.3 (A017)	Improved Accident Monitoring	All Plants	C	PG&E letters of Sept. 9, 1983, and DCL-84-298, dated Sept. 4, 1984 supplemented by letter, DCL-85-088, dated March 1, 1985 provided PG&E's response to Supplement 1 of NUREG-0737 summarizing compliance with Regulatory Guide 1.97, Rev. 3 for Unit 1. In letter DCL-86-086, dated March 271986, PG&E provided information regarding the unavailability of acceptable radioactivity concentration monitors and boric acid charging flow meters. In PG&E letter DCL-90-037, dated Feb. 1, 1990, PG&E informed the NRC of installation of a qualified flowmeter in Unit 1. (Same status for Unit 2.)
75 (B076)	Item 1.1 - Post-Trip Review(Program Description and Procedure)	All Plants	NC	PG&E letters DCL-84-034, dated Feb. 1, 1984, and DCL-85-025, dated Jan. 24, 1985, provided PG&E's response to this item. NRC letter dated May 15, 1985, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 2.)

* See Attachment for Coding Definition

FACILITY NAME: Diablo Canyon Power Plant Unit 1
DOCKET NO.: 50-275. OL-DPR-80
LICENSEE: Pacific Gas and Electric Company

STATUS OF LICENSEE IMPLEMENTATION OF GENERIC SAFETY ISSUES

RESOLVED WITH IMPOSITION OF REQUIREMENTS OR CORRECTIVE ACTIONS

GSI/(MPA No)	TITLE	APPLICABILITY	STATUS*	COMMENTS
75 (B085)	Item 1.2 - Post-Trip Review - Data and Information Capability	All Plants	NC	PG&E letter DCL-84-242, dated June 27, 1984, provided PG&E's response to this item. NRC letter dated June 25, 1984, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 2.)
75 (B077)	Item 2.1 - Equipment Classification and Vendor Interface Data and Information Capability (Reactor Trip System Components)	All Plants	C	PG&E letters DCL-85-151, dated April 18, 1985, and DCL-87-057, dated Mar. 24, 1987, provided PG&E's response to this item. NRC letters dated Oct. 27, 1986 and July 24, 1987, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 2.)
75 (B086)	Item 2.2.1 - Equipment Classification for Safety-Related Components	All Plants	C	PG&E letter DCL-87-156, dated June 30, 1987, provided PG&E's response to this item. NRC letter dated Oct. 30, 1987, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 2.)
75 (L003)	Item 2.2.2 - Vendor Interface for Safety-Related Components	All Plants	E 9/90	PG&E letter DCL-87-156, dated June 30, 1987, provided PG&E's response to this item. Generic Letter 90-03 provided a relaxation of the NRC Staff's position on this item. PG&E's response is due to the NRC by Sept. 25, 1990. (Same status for Unit 2.)
75 (B078)	Items 3.1.1 & 3.1.2 - Post- Maintenance Testing (Reactor Trip System Components)	All Plants	NC	PG&E letters DCL-85-002, dated Jan. 2, 1985, and DCL-85-151, dated April 18, 1985, provided PG&E's response to these items. NRC letter dated April 10, 1986, provided acceptance of PG&E's actions regarding these items. (Same status for Unit 2.)
75 (B079)	Item 3.1.3 - Post-Maintenance Testing-Changes to Test Requirements (Reactor Trip System Components)	All Plants	NC	PG&E letters DCL-85-002, dated Jan. 2, 1985, and DCL-85-151, dated April 18, 1985, provided PG&E's response to this item. NRC letter dated June 26, 1986, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 2.)
75 (B087)	Items 3.2.1 & 3.2.2 - Post- Maintenance Testing (All Other Safety-Related Components)	All Plants	C	PG&E letter DCL-86-074, dated March 20, 1986, provided PG&E's response to these items. NRC letter dated Oct. 21, 1986, provided acceptance of PG&E's actions regarding these items. (Same status for Unit 2.)
75 (B088)	Item 3.2.3 - Post-Maintenance Testing-Changes to Test Requirements (All Other Safety-Related Components)	All Plants	C	PG&E letter DCL-86-074, dated March 20, 1986, provided PG&E's response to this item. NRC letter dated June 26, 1986, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 2.)

* See Attachment for Coding Definition

FACILITY NAME: Diablo Canyon Power Plant Unit 1
DOCKET NO.: 50-275. OL-DPR-80
LICENSEE: Pacific Gas and Electric Company

STATUS OF LICENSEE IMPLEMENTATION OF GENERIC SAFETY ISSUES

RESOLVED WITH IMPOSITION OF REQUIREMENTS OR CORRECTIVE ACTIONS

GSI/(MPA No)	TITLE	APPLICABILITY	STATUS*	COMMENTS
75 (B080)	Item 4.1 - Reactor Trip System Reliability (Vendor-Related Modifications)	All Plants	NC	PG&E letter dated Nov. 7, 1983, provided PG&E's response to this item. NRC letter dated July 8, 1985, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 2.)
75 (B081)	Items 4.2.1 & 4.2.2 - Reactor Trip System Reliability - Maintenance and Testing (Preventive Maintenance and Surveillance Program for Reactor Trip Breakers)	All PWRs	C	PG&E letters dated Nov. 7, 1983, DCL-85-070 dated Feb. 21, 1985, and DCL-85-151, dated April 18, 1985, provided PG&E's response to these items. DCL-88-132, dated May 17, 1988, provided additional information for Item 4.2.1. NRC letter dated June 24, 1985, provided acceptance of PG&E's actions regarding these items. (Same status for Unit 2.)
75 (B082)	Item 4.3 - Reactor Trip System Reliability - Design Modifications (Automatic Actuation of Shunt Trip Attachment for Westinghouse and B&W Plants)	All W and B&W Plants	C	PG&E letters dated Dec. 20, 1983, DCL-84-194, dated May 24, 1984, DCL-84-211, dated June 6, 1984, DCL-84-241, dated June 27, 1984, DCL-84-347, dated Nov. 7, 1984, DCL-86-336, dated Nov. 20, 1986 and DCL-88-298, dated Dec. 9, 1988, provided PG&E s response to this item. NRC letters dated May 16, 1984 and Jan. 6, 1989, provided acceptance of PG&E's actions regarding these items. (Same status for Unit 2.)
75 (B090)	Item 4.3 - Reactor Trip System Reliability - Tech Spec Changes (Automatic Actuation of Shunt Trip Attachment for Westinghouse and B&W Plants)	All W & B&W Plants	C	PG&E letters DCL-84-194, dated May 24, 1984, DCL-84-210, dated June 6, 1984, DCL-85-360, dated Dec. 6, 1985, DCL-88-307, dated Dec. 19, 1988, and DCL-89-074, dated Mar. 23, 1989, provided PG&E's response to this item. NRC letters dated May 16, 1984 and Jan. 6, 1989, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 2.)
75 (B091)	Item 4.4 - Reactor Trip System Reliability (Improvements in Maintenance and Test Procedures for B&W Plants)	All B&W Plants	NA	
75 (B092)	Item 4.5.1 - Reactor Trip System Reliability-Diverse Trip Features (System Functional Testing)	All Plants	NC	PG&E letters DCL-84-241, dated June 27, 1984, DCL-84-347, dated Nov. 7, 1984, DCL-85-025, dated Jan. 24, 1985, and DCL-85-151, dated Apr. 18, 1985, provided PG&E's response to this item. NRC letter dated July 8, 1985, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 2.)
75 (B093)	Items 4.5.2 & 4.5.3 - Reactor Trip System Reliability - Test Alternatives and Intervals (System Functional Testing)	All Plants	NC	PG&E letters dated Nov. 7, 1983 and DCL-84-241, dated June 27, 1984, provided PG&E's response to Item 4.5.2. PG&E letter DCL-84-364, dated Nov. 30, 1984, provided PG&E's response to Item 4.5.3. NRC letter dated Mar. 18, 1987, provided acceptance of PG&E's actions regarding Item 4.5.2. NRC letter dated May 30, 1989 provided acceptance of PG&E's actions regarding Item 4.5.3. (Same status for Unit 2.)

* See Attachment for Coding Definition

FACILITY NAME: Diablo Canyon Power Plant Unit 1
DOCKET NO.: 50-275. OL-DPR-80
LICENSEE: Pacific Gas and Electric Company

STATUS OF LICENSEE IMPLEMENTATION OF GENERIC SAFETY ISSUES

RESOLVED WITH IMPOSITION OF REQUIREMENTS OR CORRECTIVE ACTIONS

GSI/(MPA No)	TITLE	APPLICABILITY	STATUS*	COMMENTS
86 (B084)	Long Range Plan for Dealing with Stress Corrosion Cracking in BWR Piping	All BWRs	NA	
93 (B098)	Steam Binding of Auxiliary Feedwater Pumps	All PWRs	C	PG&E letters DCL-86-047, dated Feb. 25, 1986 and DCL-88-135, dated May 23, 1988, responded to GL 85-01 and GL 88-03 respectively. NRC letter dated Feb. 23, 1989, indicated that PG&E's response to GL 88-03 was satisfactory and that procedure implementation had been verified by NRC Region V. (Same status for Unit 2.)
99 (L817)	RCS/RHR Suction Line Valve Interlock on PWRs	All PWRs	I 5/91	PG&E letter DCL 87-187, dated Aug. 4, 1987, submitted WCAP-11117 which provided justification for removal of the RHR System Autoclosure Interlock (ACI) Function. NRC letter dated February 17, 1988, provide the NRC Staff's safety evaluation and acceptance for removal of the ACI. Removal of the ACI and procedural enhancements have been completed for Unit 1. PG&E letter DCL-87-233, dated Sept. 18, 1987 responded to GL 87-12 regarding loss of RHR while the RCS is partially filled. PG&E letters DCL-89-005, dated Jan. 6, 1989, and DCL-89-030 dated Feb. 6, 1989, responded to GL 88-17 regarding loss of decay heat removal and expeditious actions and programmed enhancements. NRC letter dated April 26, 1989, provided acceptance of PG&E's expeditious actions and provided comments on PG&E's actions. Provision for Unit 1 RHR pump motor current trending is scheduled for installation during the fourth refueling outage (May 1991).
124	Auxiliary Feedwater System Reliability	AN0-1&2 Pancho Seco, Prairie Island 1&2, Crystal River-3, Ft. Calhoun	NA	
A-13 (B017)	Snubber Operability Assurance - Hydraulic Snubbers	All Plants	NC	The Units 1 and 2 Combined Technical Specifications, issued Aug. 26, 1985. Specification 3/4.7.7 provide operability and surveillance requirements for Diablo Canyon consistent with the Westinghouse Standard Technical Specifications. (Same status for Unit 2.)
A-13 (B022)	Snubber Operability Assurance - Mechanical Snubbers	All Plants	NC	The Units 1 and 2 Combined Technical Specifications, issued Aug. 26, 1985. Specification 3/4.7.7 provide operability and surveillance requirements for Diablo Canyon consistent with the Westinghouse Standard Technical Specifications. (Same status for Unit 2.)

* See Attachment for Coding Definition

FACILITY NAME: Diablo Canyon Power Plant Unit 1
DOCKET NO.: 50-275. OL-DPR-80
LICENSEE: Pacific Gas and Electric Company

STATUS OF LICENSEE IMPLEMENTATION OF GENERIC SAFETY ISSUES

RESOLVED WITH IMPOSITION OF REQUIREMENTS OR CORRECTIVE ACTIONS

GSI/(MPA No)	TITLE	APPLICABILITY	STATUS*	COMMENTS
A-16 (D012)	Steam Effects on BWR Core Spray Distribution	Oyster Creek & NMP-1	NA	
A-35 (B023)	Adequacy of Offsite Power Systems	All Plants	NC	PG&E letters dated Jan. 24, 1978, June 13, 1978, and Oct. 4, 1978, provided information regarding system protection for degraded voltage conditions. (Same status for Unit 2.)
B-10	Behavior of BWR Mark III Containments	All BWR Mark III Plants	NA	
B-36	Develop Design, Testing and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units for Engineered Safety Features Systems and for Normal Ventilation Systems	All Plants with OL Applications After 4/1/80	NA	
B-63 (B045)	Isolation of Low Pressure Systems Connected to the Reactor Coolant System Pressure Boundary	All Plants	C	PG&E letters DCL-85-320, dated Oct. 11, 1985, DCL-86-033, dated Feb. 13, 1986, DCL-86-238, dated Aug. 12, 1986, and DCL-87-129, dated June 8, 1987, provided information regarding periodic testing of RCS pressure isolation valves in accordance with TS 4.4.6.2. NRC letter dated July 27, 1987, issued Amendment No. 16 for Unit 1 to include additional valves in TS Table 3.4-1. (Same status for Unit 2.)

* See Attachment for Coding Definition

FACILITY NAME: Diablo Canyon Power Plant Unit 2
DOCKET NO.: 50-275. OL-DPR-80
LICENSEE: Pacific Gas and Electric Company

STATUS OF LICENSEE IMPLEMENTATION OF GENERIC SAFETY ISSUES

RESOLVED WITH IMPOSITION OF REQUIREMENTS OR CORRECTIVE ACTIONS

GSI/(MPA No)	TITLE	APPLICABILITY	STATUS*	COMMENTS
40 (B065)	Safety Concerns Associated With Pipe Breaks In The BWR Scram System	All BWRs	NA	
41 (B058)	BWR Scram Discharge Volume Systems	All BWRs	NA	
43 (B107)	Reliability Of Air Systems	All Plants	C	PG&E letters DCL-89-041, dated Feb. 21, 1989, and DCL-89-154, dated June 6, 1989 provided PG&E's response to Generic Letter 88-14. The letter provided PG&E's actions and schedule to implement the GL 88-14 recommendations. NRC letter dated June 12, 1989, provided acceptance of PG&E's actions regarding GL 88-14. GL 88-14 actions are completed, however, PG&E is continuing an effort to identify air system improvements for enhanced system performance. (Same status for Unit 1.)
51 (L913)	Improving the Reliability of Open-Cycle Service Water Systems	All Plants	I 12/91	PG&E letter DCL-90-027, dated Jan. 26, 1990 provided PG&E's plans and schedules regarding the establishment of programs to implement GL 89-13 recommendations. The commitments are being completed consistent with the schedule provided in DCL-90-027 with expected completion of the Unit 2 and common Units 1 and 2 actions during the 4th refueling outage of Unit 2 (December 1991). (Same status for Unit 1.)
67.3.3 (A017)	Improved Accident Monitoring	All Plants	C	PG&E letters of Sept. 9, 1983, and DCL-84-298, dated Sept. 4, 1984 supplemented by letters DCL-85-024, dated Jan. 25, 1984, and DCL-85-243, dated July 18, 1985, provided PG&E's response to Supplement 1 of NUREG-0737 summarizing compliance with Regulatory Guide 1.97, Rev. 3 for Unit 2. In letter DCL-86-086, dated March 27, 1986, PG&E provided information regarding the unavailability of acceptable radioactivity concentration monitors and boric acid charging flow meters. In PG&E letter DCL-90-121, dated May 7, 1990, PG&E informed the NRC of installation of a qualified flowmeter in Unit 2. (Same status for Unit 1.)
75 (B076)	Item 1.1 - Post-Trip Review (Program Description and Procedure)	All Plants	NC	PG&E letters DCL-84-034, dated Feb. 1, 1984, and DCL-85-025, dated Jan. 24, 1985, provided PG&E's response to this item. NRC letter dated May 15, 1985, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 1.)
75 (B085)	Item 1.2 - Post-Trip Review - Data and Information Capability	All Plants	NC	PG&E letter DCL-84-242, dated June 27, 1984, provided PG&E's response to this item. NRC letter dated June 25, 1984, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 1.)

* See Attachment for Coding Definition

FACILITY NAME: Diablo Canyon Power Plant Unit 2
DOCKET NO.: 50-275. OL-DPR-80
LICENSEE: Pacific Gas and Electric Company

STATUS OF LICENSEE IMPLEMENTATION OF GENERIC SAFETY ISSUES

RESOLVED WITH IMPOSITION OF REQUIREMENTS OR CORRECTIVE ACTIONS

GSI/(MPA No)	TITLE	APPLICABILITY	STATUS*	COMMENTS
75 (B077)	Item 2.1 - Equipment Classification and Vendor Interface Data and Information Capability (Reactor Trip System Components)	All Plants	C	PG&E letters DCL-85-151, dated April 18, 1985, and DCL-87-057, dated Mar. 24, 1987, provided PG&E's response to this item. NRC letters dated Oct. 27, 1986 and July 24, 1987, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 1.)
75 (B086)	Item 2.2.1 - Equipment Classification for Safety-Related Components	All Plants	C	PG&E letter DCL-87-156, dated June 30, 1987, provided PG&E's response to this item. NRC letter dated Oct. 30, 1987, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 1.)
75 (L003)	Item 2.2.2 - Vendor Interface for Safety-Related Components	All Plants	E 9/90	PG&E letter DCL-87-156, dated June 30, 1987, provided PG&E's response to this item. Generic Letter 90-03 provided a relaxation of the NRC Staff's position on this item. PG&E's response is due to the NRC by Sept. 25, 1990. (Same status for Unit 1.)
75 (B078)	Items 3.1.1 & 3.1.2 - Post- Maintenance Testing (Reactor Trip System Components)	All Plants	NC	PG&E letter DCL-85-151, dated April 18, 1985, provided PG&E's response to these items. NRC letter dated April 10, 1986, provided acceptance of PG&E's actions regarding these items. (Same status for Unit 1.)
75 (B079)	Item 3.1.3 - Post-Maintenance Testing-Changes to Test Requirements (Reactor Trip System Components)	All Plants	NC	PG&E letter DCL-85-151, dated April 18, 1985, provided PG&E's response to this item. NRC letter dated March 16, 1987, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 1.)
75 (B087)	Items 3.2.1 & 3.2.2 - Post- Maintenance Testing (All Other Safety-Related Components)	All Plants	C	PG&E letter DCL-86-227, dated Aug. 1, 1986, provided PG&E's response to this item. NRC letter dated Oct. 21, 1986, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 1.)
75 (B088)	Item 3.2.3 - Post-Maintenance Testing-Changes to Test Requirements (All Other Safety-Related Components)	All Plants	C	PG&E letter DCL-86-227, dated Aug. 1, 1986, provided PG&E's response to this item. NRC letter dated March 16, 1987, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 1.)
75 (B080)	Item 4.1 - Reactor Trip System Reliability (Vendor-Related Modifications)	All Plants	NC	PG&E letter dated Nov. 7, 1983, provided PG&E's response to this item. NRC letter dated July 8, 1985, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 1.)

* See Attachment for Coding Definition

FACILITY NAME: Diablo Canyon Power Plant Unit 2
DOCKET NO.: 50-275. OL-DPR-80
LICENSEE: Pacific Gas and Electric Company

STATUS OF LICENSEE IMPLEMENTATION OF GENERIC SAFETY ISSUES

RESOLVED WITH IMPOSITION OF REQUIREMENTS OR CORRECTIVE ACTIONS

GSI/(MPA No)	TITLE	APPLICABILITY	STATUS*	COMMENTS
75 (B081)	Items 4.2.1 & 4.2.2 - Reactor Trip System Reliability - Maintenance and Testing (Preventive Maintenance and Surveillance Program for Reactor Trip Breakers)	All PWRs	C	PG&E letters dated Nov. 7, 1983, DCL-85-070, dated Feb. 21, 1985, and DCL-85-151, dated April 18, 1985, provided PG&E's response to these items. DCL-88-132, dated May 17, 1988, provided additional information for Item 4.2.1. NRC letter dated June 24, 1985, provided acceptance of PG&E's actions regarding these items. (Same status for Unit 1.)
75 (B082)	Item 4.3 - Reactor Trip System Reliability - Design Modifications (Automatic Actuation of Shunt Trip Attachment for Westinghouse and B&W Plants)	All W and B&W Plants	C	PG&E letters dated Dec. 20, 1983, DCL-84-194, dated May 24, 1984, DCL-84-211, dated June 6, 1984, DCL-84-241, dated June 27, 1984, DCL-84-347, dated Nov. 7, 1984, DCL-86-336, dated Nov. 20, 1986, and DCL-88-298, dated Dec. 9, 1988, provided PG&E's response to this item. NRC letters dated May 16, 1984 and Jan. 6, 1989, provided acceptance of PG&E's actions regarding these items. (Same status for Unit 1.)
75 (B090)	Item 4.3 - Reactor Trip System Reliability - Tech Spec Changes (Automatic Actuation of Shunt Trip Attachment for Westinghouse and B&W Plants)	All W & B&W Plants	C	PG&E letters DCL-84-194, dated May 24, 1984, DCL-85-360, dated Dec. 6, 1985, DCL-88-307, dated Dec. 19, 1988, and DCL-89-074, dated Mar. 23, 1989, provided PG&E's response to this item. NRC letters dated May 16, 1984 and Jan. 6, 1989, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 1.)
75 (B091)	Item 4.4 - Reactor Trip System Reliability (Improvements in Maintenance and Test Procedures for B&W Plants)	All B&W Plants	NA	
75 (B092)	Item 4.5.1 - Reactor Trip System Reliability-Diverse Trip Features (System Functional Testing)	All Plants	NC	PG&E letters DCL-84-241, dated June 27, 1984, DCL-84-347, dated Nov. 7, 1984, DCL-85-025, dated Jan. 24, 1985, and DCL-85-151, dated Apr. 18, 1985, provided PG&E's response to this item. NRC letter dated July 8, 1985, provided acceptance of PG&E's actions regarding this item. (Same status for Unit 1.)
75 (B093)	Items 4.5.2 & 4.5.3 - Reactor Trip System Reliability - Test Alternatives and Intervals (System Functional Testing)	All Plants	NC	PG&E letters dated Nov. 7, 1983 and DCL-84-241 dated June 27, 1984, provided PG&E's response to Item 4.5.2. PG&E letter DCL-84-364, dated Nov. 30, 1984, provided PG&E's response to Item 4.5.3. NRC letter dated Mar. 18, 1987 provided acceptance of PG&E's actions regarding Item 4.5.2. NRC letter dated May 30, 1989, provided acceptance of PG&E's actions regarding Item 4.5.3. (Same status for Unit 1.)
86 (B084)	Long Range Plan for Dealing with Stress Corrosion Cracking in BWR Piping	All BWRs	NA	

* See Attachment for Coding Definition

FACILITY NAME: Diablo Canyon Power Plant Unit 2
DOCKET NO.: 50-275. OL-DPR-80
LICENSEE: Pacific Gas and Electric Company

STATUS OF LICENSEE IMPLEMENTATION OF GENERIC SAFETY ISSUES

RESOLVED WITH IMPOSITION OF REQUIREMENTS OR CORRECTIVE ACTIONS

GSI/(MPA No)	TITLE	APPLICABILITY	STATUS*	COMMENTS
93 (B098)	Steam Binding of Auxiliary Feedwater Pumps	All PWRs	C	PG&E letters DCL-86-047, dated Feb. 25, 1986 and DCL-88-135, dated May 23, 1988, responded to GL 85-01 and GL 88-03 respectively. NRC letter dated Feb. 23, 1989, indicated that PG&E's response to GL 88-03 was satisfactory and that procedure implementation had been verified by NRC Region V. (Same status for Unit 1.)
99 (L817)	RCS/RHR Suction Line Valve Interlock on PWRs	All PWRs	C	PG&E letter DCL 87-187, dated Aug. 4 1987 submitted WCAP-11117 which provided justification for removal of the RHR System Autoclosure Interlock (ACI) Function. NRC letter dated February 17, 1988, provide the NRC Staff's safety evaluation and acceptance for removal of the ACI. Removal of the ACI and procedural enhancements have been completed for Unit 2. PG&E letter DCL-87-233, dated Sept. 18, 1987, responded to GL 87-12 regarding loss of RHR while the RCS is partially filled. PG&E letters DCL-89-005, dated Jan. 6, 1989, and DCL-89-030, dated Feb. 6, 1989, responded to GL 88-17 regarding loss of decay heat removal and expeditious actions and programmed enhancements. NRC letter dated April 26, 1989, provided acceptance of PG&E's expeditious actions and provided comments on PG&E's actions.
124	Auxiliary Feedwater System Reliability	AND-1&2, Rancho Seco, Prairie Island 1&2, Crystal River-3, Ft. Calhoun	NA	
A-13 (B017)	Snubber Operability Assurance - Hydraulic Snubbers	All Plants	NC	The Units 1 and 2 Combined Technical Specifications, issued Aug. 26, 1985. Specification 3/4.7.7 provide operability and surveillance requirements for Diablo Canyon consistent with the Westinghouse Standard Technical Specifications. (Same status for Unit 1.)
A-13 (B022)	Snubber Operability Assurance - Mechanical Snubbers	All Plants	NC	The Units 1 and 2 Combined Technical Specifications, issued Aug. 26, 1985. Specification 3/4.7.7 provide operability and surveillance requirements for Diablo Canyon consistent with the Westinghouse Standard Technical Specifications. (Same status for Unit 1.)

* See Attachment for Coding Definition

FACILITY NAME: Diablo Canyon Power Plant Unit 2
DOCKET NO.: 50-275. OL-DPR-80
LICENSEE: Pacific Gas and Electric Company

STATUS OF LICENSEE IMPLEMENTATION OF GENERIC SAFETY ISSUES

RESOLVED WITH IMPOSITION OF REQUIREMENTS OR CORRECTIVE ACTIONS

GSI/(MPA No)	TITLE	APPLICABILITY	STATUS*	COMMENTS
A-16 (D012)	Steam Effects on BWR Core Spray Distribution	Oyster Creek & NMP-1	NA	
A-35 (B023)	Adequacy of Offsite Power Systems	All Plants	NC	PG&E letters dated Jan. 24, 1978, June 13, 1978, and Oct. 4, 1978, provided information regarding system protection for degraded voltage conditions. (Same status for Unit 1.)
B-10	Behavior of BWR Mark III Containments	All BWR Mark III Plants	NA	
B-36	Develop Design, Testing and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units for Engineered Safety Features Systems and for Normal Ventilation Systems	All Plants with OL Applications After 4/1/80	NA	
B-63 (B045)	Isolation of Low Pressure Systems Connected to the Reactor Coolant System Pressure Boundary	All Plants	C	PG&E letters DCL-85-320, dated Oct. 11, 1985, DCL-86-033, dated Feb. 13, 1986, DCL-86-238, dated Aug. 12, 1986, and DCL-87-129, dated June 8, 1987, provided information regarding periodic testing of RCS pressure isolation valves in accordance with TS 4.4.6.2. NRC letter dated July 27, 1987, issued Amendment No. 15 for Unit 2 to include additional valves in TS Table 3.4-1. (Same status for Unit 1.)

* See Attachment for Coding Definition

Attachment

1. NA - GSI is not applicable.

2. NC - GSI is applicable but no changes were necessary to implement the resolution, or the GSI implementation was completed prior to issuance of the operating license and no post-licensing changes were necessary.

3. C - GSI is applicable; submittal of information and/or changes were necessary and such submittals were made or changes are complete.

4. I - GSI is applicable and changes were necessary but such changes are not yet fully implemented.

5. E - Implementation guidance for a resolved GSI was issued recently and is still being evaluated.

Pacific Gas and Electric Company

Diablo Canyon Power Plant
P.O. Box 56
Avila Beach CA 93424
805/595-7351

John D. Townsend
Vice President-Diablo Canyon
Operations and Plant Manager

November 1, 1991

PG&E Letter No. DCL-91-270

William R. Leonard, Executive Officer
California Regional Water Quality Control Board
Central Coast Region
81 Higuera Street, Suite 200
San Luis Obispo, CA 93401-5414

Dear Mr. Leonard:

Biofouling Control Strategies
Diablo Canyon Power Plant - NPDES No. CA0003751

The purpose of this letter is to inform you of several changes in the Diablo Canyon Power Plant biofouling control strategies. None of the changes being implemented or planned will significantly change the character of the plant discharge. PG&E personnel discussed the following strategies with you in July 1991, and since then:

1. PG&E has replaced the gaseous chlorination system with an aqueous 12.5% sodium hypochlorite chlorination system. This strategy for biofouling control in the once-through cooling water systems will help ensure personnel safety.

2. PG&E is adding a sodium bisulfite injection dechlorination system to the discharge of the once-through cooling water. This strategy will allow the plant to reach a higher concentration of free chlorine at the condenser while meeting the 1990 Ocean Plan limits at the discharge.

3. PG&E will initiate a program to continuously chlorinate the Auxiliary Saltwater System, Discharge 001B, as recommended in Nuclear Regulatory Commission Generic Letter 89-13.

4. PG&E continues to consider the possible benefits of bromide injection in conjunction with chlorination to improve the biofouling control system. PG&E will provide additional information on bromide to you prior to first use.

Enclosed is a "Summary of Changes in the Diablo Canyon Power Plant Biofouling Control Strategies." This summary provides additional detail on the strategies that are being implemented or planned.

If you have any questions, please call Jeff Gardner at (415) 972-4004.

Sincerely,

/S/: D. Miklush for JDT
John D. Townsend

5514S/85K/BJB/935

bcc: BJBerndt (333/A1192A)
JVBoots (DCPP-104/5/517)
JEGardner (77/1409)
JNGillem (DCPP-104/5/16A)
RWLorenz (77/1411)
DBMiklush (DCPP-104/5/503)
DCSommerville (DCPP-104/4/22B)
TCWilson (DCPP-104/5/3A)

Enclosure

ENCLOSURE

SUMMARY OF CHANGES IN THE DIABLO CANYON POWER PLANT BIOFOULING CONTROL STRATEGIES

1. To ensure personnel safety, PG&E has reduced the inventory of gaseous chlorine by upgrading the biofouling control system to an aqueous hypochlorite chlorination system. The gaseous chlorination system was removed in May 1991. In its place, PG&E has installed a chlorination system that injects a 12.5% sodium hypochlorite solution into the cooling water flow through the existing distribution system of the intake structure. The biofouling control action of the hypochlorite is the same as gaseous chlorine. Total chlorine residual will remain the discharge monitoring parameter. PG&E reports total chlorine residual using a method that yields total residual oxidant (TRO).

2. In order to ensure compliance with the discharge limitations set by the 1990 Ocean Plan, PG&E is installing a dechlorination system. This system will inject sodium bisulfite ($NaHSO_3$) into the condenser outlet water box concurrent with chlorination at the intake structure. The bisulfite readily reduces any remaining residual oxidant introduced at the intake structure. PG&E identified the future use of dechlorination as a possibility to ensure compliance with discharge limitations in PG&E Engineering Report, submitted to your office on November 12, 1990 (PG&E Letter No. DCL-90-268).

   PG&E plans to conduct tests that evaluate the benefit of intermittent hypochlorite injections in sequence with sodium bisulfite injections spaced throughout the day for the control of biofouling. It is PG&E's understanding that the time duration limits presented in the 1990 Ocean Plan apply only to chlorine discharges. Continuous or intermittent chlorination with dechlorination yielding no chlorine discharge would not be time limited.

3. As recommended by U.S. Nuclear Regulatory Commission Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," dated July 18, 1989, PG&E will begin a program to continuously chlorinate the safety-related Auxiliary Saltwater System (ASW). Generic Letter 89-13 recommends continuous chlorination of this system as the most desirable method for biofouling control. PG&E plans to begin chlorination of the ASW at a level of approximately 1.0 ppm to optimize biofouling control while maintaining compliance with the 1990 Ocean Plan. Under normal operating conditions, the two ASW system flows join the two main circulating water pump discharge flows from the condensers of each unit. These combined flows result in a dilution of 22,000 gpm by approximately 1,600,000 gpm. The calculated TRO at the discharge is below the detection limit when accounting for the dilution factor. Chlorination will be interrupted and adjusted when the circulating water pump discharges are not providing adequate flow. PG&E plans to evaluate discharge TRO

concentrations initially to determine normal conditions, and then periodically thereafter.

4. PG&E is continuing to consider improving the biofouling control system with the use of bromide (sodium bromide, NaBr). This strategy in which sodium bromide is injected simultaneously with sodium hypochlorite has been used successfully in the utility industry. The resultant reaction is the same as that which normally takes place in seawater due to the high natural concentration of bromine:

   $$Br^- + HOCl \rightarrow HOBr + Cl^-$$

   In seawater, the chemical responsible for biofouling control is hypobromous acid (HOBr). The dechlorination system will also work as a system for debromination. The HOBr reaction with sodium bisulfite is:

   $$SO_3^{-2} + HOBr \rightarrow SO_4^{-2} + HBr$$

   Therefore, the use of chlorine or bromine will not significantly change the nature of the discharge.

Pacific Gas and Electric Company

77 Beale Street
San Francisco, CA 94106
415/973-4684

Gregory M. Rueger
Senior Vice President and
General Manager
Nuclear Power Generation

November 25, 1991

PG&E Letter No. DCL-91-286

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

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Supplemental Response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment"

Gentlemen:

Generic Letter (GL) 89-13 required that licensees submit an initial response advising the NRC whether they had established programs to implement the five GL 89-13 recommendations, and also required that licensees submit a supplemental response within 30 days following completion of initial program actions. PG&E Letter No. DCL-90-027, dated January 26, 1990, provided initial information to the NRC regarding PG&E's program in accordance with GL 89-13. PG&E completed the initial GL 89-13 program actions during the fourth refueling outage for each unit at Diablo Canyon, which ended on April 4, 1991, for Unit 1 and on October 26, 1991, for Unit 2. This letter documents completion of the initial program actions in accordance with GL 89-13 requirements. The enclosure to this letter provides a summary description of the actions PG&E has taken to address each of the GL 89-13 recommendations.

Sincerely,

/S/: Greg Rueger
Gregory M. Rueger

cc: Ann P. Hodgdon
John B. Martin
Philip J. Morrill
Harry Rood
Howard J. Wong
CPUC
Diablo Distribution

Enclosure

5551S/0085K/ALN/2232

ENCLOSURE

SUPPLEMENTAL RESPONSE TO GENERIC LETTER 89-13, "SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT"

ENCLOSURE

SUPPLEMENTAL RESPONSE TO GENERIC LETTER 89-13, "SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT"

This enclosure provides a summary description of the actions PG&E has taken to address the five recommendations of Generic Letter (GL) 89-13.

> Recommendation 1: *"For open-cycle service water systems, implement and maintain an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling."*

PG&E has implemented an ongoing program to visually inspect the auxiliary saltwater (ASW) system intake structure, including the pump bays and screens, during refueling outages. This program includes inspection for macroscopic biological fouling (macrofouling), sediment, and corrosion, as well as actions to be taken for evaluation and disposition of any problems identified. The initial inspections were completed for Units 1 and 2 during their respective fourth refueling outages. These inspections found that ASW system macrofouling was minimal except in areas of turbulent flow and at joints in the piping where significant amounts of macrofouling were noted. However, the ASW system flow testing has demonstrated that the observed macrofouling has not adversely affected ASW system operability.

PG&E has reviewed several biofouling control methods, including fresh water layup (stagnation) and intermittent and continuous halogenation. PG&E currently uses intermittent halogenation with sodium hypochlorite and also periodic stagnation with seawater as trains of the ASW system are rotated. PG&E has found that intermittent halogenation and stagnation are adequate to control microfouling and to some extent macrofouling. However, PG&E plans to enhance the control program to be more effective in minimizing the impacts of macrofouling by implementing a program to continuously halogenate the ASW system to minimize both micro and macrofouling, which will include halogenated stagnation as a part of ASW system train rotation. Until the continuous halogenation program is in place, PG&E will continue to perform intermittent halogenation coupled with periodic stagnation.

With respect to ASW system cooling loop flushing and flow testing, as stated in our original GL 89-13 response, STP M-26, "ASW System Performance Monitoring," and the Annunciator Response Procedure PK01-01, "ASW SYS HS DELTA P/HDR PRESS," meet the recommendations of GL 89-13 control technique C. The Units 1 and 2 fourth refueling outage inspections have confirmed that current layup and flushing procedures, in conjunction with the other aspects of the surveillance and control program, are adequate to assure ASW system operability but do not minimize the potential for macrofouling to the extent that PG&E would like based on recent operating experience. To minimize ASW system unavailability due to heat exchanger cleaning, PG&E is implementing a design change to provide continuous halogenation as mentioned above.

PG&E will continue to evaluate the ongoing surveillance and control program for effectiveness and modify the program as necessary.

Recommendation 2: *"Conduct a test program to verify the heat transfer capability of all safety-related heat exchangers cooled by service water. The total test program should consist of an initial test program and a periodic retest program. Both the initial test program and the periodic retest program should include heat exchangers connected to or cooled by one or more open-cycle systems as defined above.*

"An equally effective program to ensure satisfaction of the heat removal requirements of the service water system would also be acceptable. An example of an alternative action that would be acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing for degraded performance of the heat exchanger."

As stated in our original response to GL 89-13, PG&E discussed and has since implemented an alterative monitoring program that combines flow testing, trending, ASW system component inspections, and regular preventive maintenance. The procedures and inspections for this program have been established and were performed during the Units 1 and 2 fourth refueling outages, and frequencies of performance were established or confirmed in response to the observations during these outages.

PG&E also performed ASW system open-cycle heat exchanger (also referred to as component cooling water (CCW) heat exchanger) performance tests and used a computer model to predict heat exchanger performance at design heat loads. Although these tests exhibited significant sensitivity to instrument inaccuracies due to the low heat loads measured, the computer model predicted that the heat exchanger would remove the design basis heat load at design conditions. PG&E is considering future testing and use of the computer model for heat exchanger trending. However, any future testing would be considered as additional information and an enhancement to the established alternative monitoring program.

Recommendation 3: *"Ensure by establishing a routine inspection and maintenance program for open-cycle service water system piping and components that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of the safety-related systems supplied by service water."*

PG&E conducted ASW system piping inspections during the Unit 2 third refueling outage and the Units 1 and 2 fourth refueling outages. These inspections showed only limited amounts of biofouling except as noted above, no erosion, and limited silting. With the exception of two locations where minor defects in the piping inner lining were noted, no corrosion was found. Actions were taken to resolve the conditions found during the inspections, including repair of the pipe and pipe inner coating for the defects and corrosion. Overall, the piping inspections showed the ASW system piping lining to be in excellent condition and therefore able to meet its function as a protective barrier. PG&E has established a routine inspection and maintenance program to ensure that ASW system performance is not adversely impaired.

Recommendation 4: *"Confirm that the service water system will perform its intended function in accordance with the licensing basis for the plant. Reconstitution of the design basis of the system is not intended. This confirmation should include a review of the ability to perform required safety functions in the event of failure of a single active component. To ensure that the as-built system is in accordance with the appropriate license basis documentation, this confirmation should include recent (within the past 2 years) system walkdown inspections."*

Design Criteria Memoranda (DCMs) for the ASW and CCW systems were completed in 1990. Also, the PG&E Quality Assurance Department performed a safety system functional audit and review in 1990 for these systems. No significant deficiencies were identified, and the minor problems identified during these activities were resolved in accordance with PG&E's procedures for resolving nonconforming conditions. In addition, the system and system design engineers continued to conduct their regular system walkdowns. These actions provide confirmation that the ASW system will perform its intended function in accordance with the licensing basis and that the as-built system is in accordance with the appropriate licensing basis documentation.

Recommendation 5: *"Confirm that maintenance practices, operating and emergency procedures, and training that involves the service water system are adequate to ensure that safety-related equipment cooled by the service water system will function as intended and that operators of this equipment will perform effectively. This confirmation should include recent (within the past 2 years) reviews of practices, procedures, and training modules. The intent of this action is to reduce human errors in the operation, repair, and maintenance of the service water system."*

Maintenance practices, operating and emergency operating procedures, and training applicable to the ASW system were reviewed, and PG&E concluded that the existing practices, procedures, and training minimize the potential for human error and that the safety-related equipment cooled by the ASW system will function as intended. In addition, the ASW system procedures were reviewed as a part of the DCM preparation and were found to be adequate.

Pacific Gas and Electric Company

77 Beale Street
San Francisco, CA 94106
415/973-4684

Gregory M. Rueger
Senior Vice President and
General Manager
Nuclear Power Generation

November 25, 1991

PG&E Letter No. DCL-91-286

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

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Supplemental Response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment"

Gentlemen:

Generic Letter (GL) 89-13 required that licensees submit an initial response advising the NRC whether they had established programs to implement the five GL 89-13 recommendations, and also required that licensees submit a supplemental response within 30 days following completion of initial program actions. PG&E Letter No. DCL-90-027, dated January 26, 1990, provided initial information to the NRC regarding PG&E's program in accordance with GL 89-13. PG&E completed the initial GL 89-13 program actions during the fourth refueling outage for each unit at Diablo Canyon, which ended on April 4, 1991, for Unit 1 and on October 26, 1991, for Unit 2. This letter documents completion of the initial program actions in accordance with GL 89-13 requirements. The enclosure to this letter provides a summary description of the actions PG&E has taken to address each of the GL 89-13 recommendations.

Sincerely,

/S/: Greg Rueger
Gregory M. Rueger

cc: Ann P. Hodgdon
John B. Martin
Philip J. Morrill
Harry Rood
Howard J. Wong
CPUC
Diablo Distribution

Enclosure

5551S/0085K/ALN/2232

ENCLOSURE

SUPPLEMENTAL RESPONSE TO GENERIC LETTER 89-13, "SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT"

ENCLOSURE

SUPPLEMENTAL RESPONSE TO GENERIC LETTER 89-13, "SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT"

This enclosure provides a summary description of the actions PG&E has taken to address the five recommendations of Generic Letter (GL) 89-13.

> Recommendation 1: *"For open-cycle service water systems, implement and maintain an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling."*

PG&E has implemented an ongoing program to visually inspect the auxiliary saltwater (ASW) system intake structure, including the pump bays and screens, during refueling outages. This program includes inspection for macroscopic biological fouling (macrofouling), sediment, and corrosion, as well as actions to be taken for evaluation and disposition of any problems identified. The initial inspections were completed for Units 1 and 2 during their respective fourth refueling outages. These inspections found that ASW system macrofouling was minimal except in areas of turbulent flow and at joints in the piping where significant amounts of macrofouling were noted. However, the ASW system flow testing has demonstrated that the observed macrofouling has not adversely affected ASW system operability.

PG&E has reviewed several biofouling control methods, including fresh water layup (stagnation) and intermittent and continuous halogenation. PG&E currently uses intermittent halogenation with sodium hypochlorite and also periodic stagnation with seawater as trains of the ASW system are rotated. PG&E has found that intermittent halogenation and stagnation are adequate to control microfouling and to some extent macrofouling. However, PG&E plans to enhance the control program to be more effective in minimizing the impacts of macrofouling by implementing a program to continuously halogenate the ASW system to minimize both micro and macrofouling, which will include halogenated stagnation as a part of ASW system train rotation. Until the continuous halogenation program is in place, PG&E will continue to perform intermittent halogenation coupled with periodic stagnation.

With respect to ASW system cooling loop flushing and flow testing, as stated in our original GL 89-13 response, STP M-26, "ASW System Performance Monitoring," and the Annunciator Response Procedure PK01-01, "ASW SYS HS DELTA P/HDR PRESS," meet the recommendations of GL 89-13 control technique C. The Units 1 and 2 fourth refueling outage inspections have confirmed that current layup and flushing procedures, in conjunction with the other aspects of the surveillance and control program, are adequate to assure ASW system operability but do not minimize the potential for macrofouling to the extent that PG&E would like based on recent operating experience. To minimize ASW system unavailability due to heat exchanger cleaning, PG&E is implementing a design change to provide continuous halogenation as mentioned above.

PG&E will continue to evaluate the ongoing surveillance and control program for effectiveness and modify the program as necessary.

Recommendation 2: *"Conduct a test program to verify the heat transfer capability of all safety-related heat exchangers cooled by service water. The total test program should consist of an initial test program and a periodic retest program. Both the initial test program and the periodic retest program should include heat exchangers connected to or cooled by one or more open-cycle systems as defined above.*

"An equally effective program to ensure satisfaction of the heat removal requirements of the service water system would also be acceptable. An example of an alternative action that would be acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing for degraded performance of the heat exchanger."

As stated in our original response to GL 89-13, PG&E discussed and has since implemented an alterative monitoring program that combines flow testing, trending, ASW system component inspections, and regular preventive maintenance. The procedures and inspections for this program have been established and were performed during the Units 1 and 2 fourth refueling outages, and frequencies of performance were established or confirmed in response to the observations during these outages.

PG&E also performed ASW system open-cycle heat exchanger (also referred to as component cooling water (CCW) heat exchanger) performance tests and used a computer model to predict heat exchanger performance at design heat loads. Although these tests exhibited significant sensitivity to instrument inaccuracies due to the low heat loads measured, the computer model predicted that the heat exchanger would remove the design basis heat load at design conditions. PG&E is considering future testing and use of the computer model for heat exchanger trending. However, any future testing would be considered as additional information and an enhancement to the established alternative monitoring program.

Recommendation 3: *"Ensure by establishing a routine inspection and maintenance program for open-cycle service water system piping and components that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of the safety-related systems supplied by service water."*

PG&E conducted ASW system piping inspections during the Unit 2 third refueling outage and the Units 1 and 2 fourth refueling outages. These inspections showed only limited amounts of biofouling except as noted above, no erosion, and limited silting. With the exception of two locations where minor defects in the piping inner lining were noted, no corrosion was found. Actions were taken to resolve the conditions found during the inspections, including repair of the pipe and pipe inner coating for the defects and corrosion. Overall, the piping inspections showed the ASW system piping lining to be in excellent condition and therefore able to meet its function as a protective barrier. PG&E has established a routine inspection and maintenance program to ensure that ASW system performance is not adversely impaired.

Recommendation 4: *"Confirm that the service water system will perform its intended function in accordance with the licensing basis for the plant. Reconstitution of the design basis of the system is not intended. This confirmation should include a review of the ability to perform required safety functions in the event of failure of a single active component. To ensure that the as-built system is in accordance with the appropriate license basis documentation, this confirmation should include recent (within the past 2 years) system walkdown inspections."*

Design Criteria Memoranda (DCMs) for the ASW and CCW systems were completed in 1990. Also, the PG&E Quality Assurance Department performed a safety system functional audit and review in 1990 for these systems. No significant deficiencies were identified, and the minor problems identified during these activities were resolved in accordance with PG&E's procedures for resolving nonconforming conditions. In addition, the system and system design engineers continued to conduct their regular system walkdowns. These actions provide confirmation that the ASW system will perform its intended function in accordance with the licensing basis and that the as-built system is in accordance with the appropriate licensing basis documentation.

Recommendation 5: *"Confirm that maintenance practices, operating and emergency procedures, and training that involves the service water system are adequate to ensure that safety-related equipment cooled by the service water system will function as intended and that operators of this equipment will perform effectively. This confirmation should include recent (within the past 2 years) reviews of practices, procedures, and training modules. The intent of this action is to reduce human errors in the operation, repair, and maintenance of the service water system."*

Maintenance practices, operating and emergency operating procedures, and training applicable to the ASW system were reviewed, and PG&E concluded that the existing practices, procedures, and training minimize the potential for human error and that the safety-related equipment cooled by the ASW system will function as intended. In addition, the ASW system procedures were reviewed as a part of the DCM preparation and were found to be adequate.

Pacific Gas and Electric Company

77 Beale Street, Room 1451
PO. Box 770000
San Francisco, CA 94177
415/973-4684
Fax 415/973-2313

Gregory M. Rueger
Senior Vice President and
General Manager
Nuclear Power Generation

February 15, 1994

PG&E Letter No. DCL-94-037

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

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Auxiliary Saltwater System Operability

Gentlemen:

NRC Inspection Report Nos. 50-275/93-36 and 50-323/93-36, dated January 2/ 1994, identified a number of NRC unresolved items and concerns related to the operability of the auxiliary saltwater (ASW) system.

PG&E's comprehensive evaluation of current ASW system operability concludes that the ASW system is operable and capable of meeting its design basis requirements. This is based on the following actions PG&E has taken since issuance of NRC Generic Letter (GL) 89-13 in 1989; (1) The ASW system is continuously chlorinated, which effectively controls biofouling; (2) The component cooling water (CCW) heat exchangers are taken out-of-service and cleaned prior to the differential pressure (dp) reaching 140 inches, a level which PG&E's engineering analysis and empirical experience indicates is acceptable to assure the design basis capability of the ASW system; (3) PG&E has implemented a comprehensive maintenance, inspection and monitoring program in compliance with GL 89-13; and (4) PG&E's reanalysis of the results of baseline performance tests of CCW heat exchangers performed in 1991 shows that all four heat exchangers meet design basis requirements. The 1991 test result for the CCW 1-2 heat exchanger was attributable to its microfouled condition at the time of the test.

In addition to these actions, PG&E recently performed testing of the ASW pump flow through the CCW heat exchangers to provide additional information on current ASW flow rates, pump runout, and dp. This additional information confirms the effectiveness of PG&E's GL 89-13 actions and the current operability of the ASW system.

Although PG&E has concluded that the ASW system has been operable at all times since implementation of its GL 89-13 program during 1R4 and 2R4, PG&E also is conducting an analysis of ASW system operating conditions from startup

to the implementation date of GL 89-13 to assess potential past operability issues. PG&E's preliminary review indicates that the ASW system has been operable for all periods prior to PG&E's implementation of GL 89-13, with two possible exceptions. The first may have occurred in 1990 when an unusual period of potential microfouling coincided with the chlorination system being out of service for piping replacement. This coincidence of events created the potential for excessive microfouling of the Unit 1 CCW 1-2 heat exchanger. The second exception may have occurred at certain times in 1986-1988 when ASW flows may have been lower than required to support the dp setpoint used to indicate the need for heat exchanger cleaning. However, in both cases, PG&E's preliminary safety evaluation concluded that the ASW system, together with credible operator action, would have ensured that the public health and safety were not adversely affected. PG&E will provide a supplement to this letter when the final results of its past operability analysis are complete.

The NRC Inspection Report identified concerns regarding the timeliness of PG&E's corrective actions, and the accuracy and completeness of information provided by PG&E regarding ASW system operability. PG&E agrees that, at the time of the NRC inspection, it had not resolved the ASW system operability issues raised by its quality organization earlier in 1993. In retrospect, as discussed in more detail in Enclosure 3, PG&E did not resolve the quality issues as thoroughly or as quickly as PG&E management would expect. However, PG&E engineering personnel had responded to the quality issues. At that time, PG&E engineering judgment was that system operability was assured because of the effectiveness of heat exchanger maintenance programs and the design margin believed to exist for the system. As discussed above, PG&E's subsequent evaluation demonstrates that the dp setpoint is acceptable and that the ASW system has been operable since PG&E's implementation of GL 89-13. Therefore, any untimeliness did not adversely affect the public health or safety.

In regard to the Inspection Report's concerns with the accuracy and completeness of information provided by PG&E in response to GL 89-13, PG&E is committed to the highest levels of accuracy and credibility in the information it provides to the NRC and the public, and takes very seriously any issue raised relating to this commitment. Based on its comprehensive review of relevant documents and information related to this issue, PG&E believes that its statement regarding the results of heat exchanger performance testing was accurate and complete when considering the guidance in the GL, as well as the previous information PG&E had provided the NRC regarding the limitations and inconclusiveness of such testing. However, PG&E agrees that its engineering evaluation of the test results should have been more comprehensive. In regard to the status of its ASW piping inspection program, PG&E believes that its statement was accurate and complete. This is because a temporary piping inspection procedure had, in fact, been established. Piping inspections had taken place, a frequency interval of every fourth refueling outage had been set, and conversion of the temporary procedure to a permanent Surveillance Test Procedure was being formally tracked, consistent with PG&E's practices for new surveillance and maintenance programs.

Although present operation, testing, and maintenance practices provide assurance of ASW system operability, PG&E intends to take the following corrective actions. An Integrated

Problem Response Team (PRT) review of the ASW, CCW, and containment heat removal systems will be performed to assure that these systems meet their design bases requirements. Additional functional testing of the CCW heat exchangers will be performed to further verify the adequacy of maintenance programs and operational controls. Enhanced ASW flow instrumentation will be provided with local readout. To improve timeliness, PG&E's program for evaluating concerns involving potentially degraded conditions will be strengthened. In addition, engineering personnel will be counseled on the need for thoroughness and a questioning attitude in analyzing design basis issues that represent a potential challenge to system operability.

PG&E's detailed evaluations are provided in the following enclosures:

- Enclosure 1 Discussion of ASW system design basis and system operability.
- Enclosure 2 Preliminary evaluation of past operability of the ASW and CCW systems, including safety significance.
- Enclosure 3 Detailed response with PG&E's corrective actions for the specific concerns, issues, and unresolved items identified in the NRC Inspection Report.

PG&E remains confident that the overall quality of engineering for Diablo Canyon Power Plant (DCPP) remains high and that the concerns identified in the Inspection Report are atypical. PG&E's past evaluations of the CCW heat exchangers were based on reasonable engineering judgments at the time. PG&E's maintenance, testing, and inspection programs for the ASW system are comprehensive and assure continued operability of the system. PG&E believes that the corrective actions taken will assure that the concerns raised in the NRC Inspection Report and PG&E's root cause evaluation will be promptly resolved.

Sincerely,

/s/
Gregory M. Rueger

cc: Mary H. Miller
Kenneth E. Perkins
Sheri R. Peterson
Diablo Distribution

Enclosures

6352S/TLG/2237

ENCLOSURE 1

DISCUSSION OF AUXILIARY SALTWATER SYSTEM DESIGN BASIS AND SYSTEM OPERABILITY

SUMMARY

The following is a discussion of the current operability of the ASW system, its design bases, key parameters affecting operability, and PG&E's maintenance, operational, and testing activities that assure continued operability.

The ASW system is designed to remove the heat generated from normal and accident conditions at Diablo Canyon and transfer the heat to the ultimate heat sink. The primary design consideration used to accomplish this function is to maintain the CCW system temperature within its allowable limits, while maintaining containment pressure within its design limits during a loss of coolant accident (LOCA) or a main steam line break (SLB) inside containment.

Several key parameters directly or indirectly affect CCW heat exchanger heat transfer capability. These parameters and the current maintenance, operational, and testing practices that are used to control them, include:

Parameters

- Macrofouling
- Microfouling and scaling
- ASW flow and ocean temperature

Monitoring and Testing

- ASW flow and ocean temperature
- Differential pressure
- Inspections and sampling during tube cleaning

Maintenance

- Continuous chlorination
- Tube cleaning/scraping/waterjet cleaning

As discussed below, these parameters have been evaluated and are considered to be sufficiently controlled by the current operational, maintenance, and testing practices at DCPP to assure that the design basis heat removal capacity of the CCW system is

maintained. Therefore, based on PG&E's evaluations, the ASW system is operable and capable of performing its safety function.

ASW SYSTEM DESIGN HEAT TRANSFER CAPACITY

The operability of the ASW system is a function of its heat transfer capacity. The ASW system provides cooling from the ultimate heat sink, the Pacific Ocean, to the CCW system. The CCW system removes waste heat from primary plant equipment during normal plant operation, plant cooldown, and following an accident. The ASW system has been designed to remove sufficient heat from the CCW system to maintain the temperature of the CCW system within its design limits under normal, transient, and accident conditions.

The ASW system has two pumps capable of pumping seawater to the tube side of either of the two CCW heat exchangers. In addition, either heat exchanger can be supplied by an ASW pump from the other unit via a cross-tie. The CCW pumps route component cooling water to the shell side of the two CCW heat exchangers. The heat transferred to the CCW system is then transferred to the ASW system through the two CCW heat exchangers.

Following, a COCA or an MSLB inside containment, the CCW system is required to provide cooling water to the containment fan cooling units (CFCUs) for containment heat removal, and to the various engineered safeguards features (ESF) pump coolers. During the recirculation phase of a LOCA, the CCW system also cools the residual heat removal (RHR) heat exchangers. The current design limits on CCW are that the CCW water temperatures must remain at or below 120°F for continuous operation, but may exceed 120°F, up to a maximum of 132°F, for no longer than 20 minutes.

Since January 1989, the Emergency Operating Procedures the (EOPs) have included instructions for the control room operators to place the second CCW heat exchanger in service in the event that one of the two trains of ASW pumps is not operating. Since December 1991, the EOPs have included instructions, upon entry into recirculation, to reduce the number of operating CFCUs to a maximum of three, and to secure the second RHR pump if two ASW pumps and two CCW heat exchangers are not operating. These actions assure that the CCW system will operate within its design limits [See Licensee Event Report (LER) 1-84-040 (March 24, 1989); LER 1-91-018 (June 29, 1992); Final Safety Analysis Report (FSAR) Update, page 9.2-5; and NRC Safety Evaluation Report, Supplement 16, pages 9-5 to 9-7 (August 1983)].

During normal plant operation, the CCW system is designed to remove heat from the CFCUs, ESF pump coolers, and various nonessential heat loads. Only one heat exchanger is normally in service during normal plant operation. In addition, the system is designed to meet single failure criteria. Therefore, the design of each CCW heat exchanger is to remove 100 percent of the design heat load from the CCW system under both normal and accident conditions.

The temperature of the CCW system is primarily a function of heat input to the system by the CFCUs (and RHR heat exchangers during recirculation), and heat removal by the ASW system. The analysis in Westinghouse WCAP-12526, Rev. 1, Auxiliary Salt Water and Component Cooling Water Flow and Temperature Study for Diablo Canyon Units 1 and 2," provides curves establishing the acceptable combinations of ASW flow and ocean temperature such that the CCW system heat removal requirements are met, assuming that the full surface area of the CCW heat exchanger is available and that the CCW heat exchanger is operated at its design fouling factor of 0.001. The fouling factor establishes a margin that accounts for the degree to which fouling will affect heat transfer, and the fouling factor used in the design is an industry standard.

ORIGINAL DESIGN BASIS AND SUBSEQUENT REVISION IN 1983

The CCW heat exchangers were purchased in December 1969 from the Yuba Heat Transfer Corporation. The heat exchangers were designed for a heat load of 258 x 106 BTU/hr. Subsequent to the original heat exchanger specifications, Section 9.2.7 of the FSAR was issued showing that the peak heat rejection rate required was actually only 252 x 106 BTU/hr.

This maximum heat load of 252 x 10^6 BTU/hr, which prior to 1983 served as the basis for the design of the ASW system, assumed three CFCUs in operation (based upon single failure of an electrical bus). Another accident scenario was investigated in early 1983, based upon a different single failure. This new scenario assumed a design basis LOCA (doubled-ended cold leg RCS pump suction piping guillotine break) coincident with a single active failure of an ASW pump. In this event, all five CFCUs and all three CCW pumps are assumed to start. This scenario results in a higher rate of heat removal from the containment atmosphere by the CCW system. The heat input into the ASW system during this scenario is 325 x 106 BTU/hr. The CCW heat exchangers have sufficient heat removal capability to maintain the CCW supply temperature at or below the maximum allowable temperature for cooling of safeguards equipment.

The limiting CCW temperature transient has been analyzed by Westinghouse. This analysis (WCAP-12526, Rev. 1) determined, for various scenarios, the required ASW flow rate as a function of ocean water temperature to maintain the CCW temperature within its design basis limit. The results of this analysis were summarized in acceptance curves for various ASW flows and ocean temperatures. This information was incorporated into the monthly Surveillance Test Procedure (STP) M-26, "ASW System Flow Monitoring," acceptance criteria, and includes corrections to the indicated ASW flow (measured at the ASW annubars) for the test conditions. Conservatisms are applied to the STP M-26 measured flows to account for possible system alignments and ocean conditions, to assure minimum accident flow requirements are met.

NRC INSPECTION REPORT ISSUES

NRC Inspection Report Nos. 50-275/93-36 and 50-323/93-36 identified a significant unresolved item relating to the basis for the operability of the ASW system with regard to operational limits on macrofouling and microfouling. The following is PG&E's evaluation of each of these operability issues:

BACKGROUND

Macrofouling

Macrofouling is the blockage of flow through the heat exchanger tubes due to mussels and barnacles in the seawater environment, or due to any potential foreign materials. Blocked heat exchanger tubes reduce the heat transfer capability of the heat exchanger since the effective surface area is reduced. The percent of tube blockage that is acceptable before the heat transfer capability of the heat exchanger is inadequate varies according to the ocean temperature, the ASW flow, the degree of concurrent microfouling, and the type of blockage that occurs (e.g., a fully blocked tube has no heat transfer contribution, but a partially blocked tube with decreased flow around the blockage will continue to provide some heat transfer capability.) For the purpose of evaluating both heat transfer and dp, macrofouling is conservatively assumed to block the tube completely, such that its contribution to heat transfer is completely negated. This is accounted for in the heat exchanger modeling by a reduction in the effective tube surface area of the heat exchanger equal to the total surface area of the blocked tubes. However, under actual conditions, macrofouling is unlikely to cause complete tube blockage.

Microfouling and Scaling

Microfouling, as referred to in this document, includes both organic and inorganic materials that adhere to the walls of the COW heat exchanger tubes and, by their presence, degrade heat transfer at the tube surface. Organic components include bacteria, algae, fungi, and the extracellular byproducts of these organisms (e.g., polysaccharides and slime). Inorganic components include silt, scale, and other deposited minerals. The presence of an established organic layer can encourage the adhesion of inorganic materials from the seawater to the tube surface.

Scaling is related to the operation of the cathodic protection system. Calcium carbonate can be expected to plate out on the inside surface of the tube near the ends of the tubes. This is the result of the reaction of the saltwater with the cathodic protection system. The cathodic protection is designed to protect a limited area and the further the distance from the cathodic protection source, the weaker the electric potential. Therefore, the rate of deposition will be lower the further into the tube from the ends. Based on experience, the deposits due to this phenomenon occur in the last 12 to 18 inches of the tubes and for a few inches beyond the end of the tube inlet inserts.

The actual heat transfer area of the CCW heat exchanger affected by calcium carbonate deposits is approximately 2 percent of the total area. Based on observations, calcium carbonate deposits occur over a few inches on all the inlet ends of the tubes just beyond the plastic tube inserts. Deposition occurring on the outlet end of the lower section of tubes is thicker than on the inlet; this is believed to occur because the inserts on the inlet insulate the tubes from the electrochemical reaction. Since the calcium carbonate deposition is a thin layer and the affected surface area is small, the overall impact on the heat

transfer capacity is small. An evaluation has estimated the reduction in the overall heat transfer capability of the heat exchanger to be less than 1.0 percent.

Calcium carbonate deposits, along with other inorganics, can also result in buildup that could result in flow blockage through the tubes, thereby impacting thermal performance. To prevent this from occurring, PG&E has implemented a routine mechanical tube scraping each refueling outage. This interval has been shown to be effective in maintaining the buildup of deposits to less than the inside diameter of the plastic inserts on the inlet of the tubes. Therefore, macrofouling and large debris will become lodged in the inlet end of the tubes and not further down along the tube length due to inorganic depositing. However, regardless of where the flow blockage occurs along the tube length, it will be detected as a contribution to the dp measurement across the heat exchanger.

Historically, microfouling has not been a problem at DCPP because of the cold average ocean temperatures along the central coast of California. However, seasonal ocean variations called upwelling and warm ocean temperatures can affect biological growth and increase microfouling. During the spring and early summer, the prevailing northwest winds at DCPP provide the driving force that moves the warmer surface ocean layers in an offshore direction. Cold water then wells up from deeper layers to replace the displaced surface water. This water is typically rich in nutrients conducive to microbiological growth, but the water is usually at such a low temperature (45°F to 55°F) that little or no biological microfouling occurs. However, if the coastal winds decrease, the ambient seawater temperature can rise to a point where the combination of nutrients and warmer temperatures (above approximately 58°F daily average ocean temperature) can allow microfouling to proliferate if accompanied by a lack of adequate biofouling controls. A historical review of the environmental and ASW operating conditions at DCPP indicates that there has been one short period when a combination of these factors created a potential for excessive microfouling. This period was July-August 1990, when the batch chlorination system was out-of-service while cast iron piping in the system was being replaced, and the ambient seawater temperature exceeded 58°F following an ocean upwelling period.

Heat Exchanger Differential Pressure

Continuous monitoring of the dp across the heat exchanger is an important diagnostic tool used to assess the heat exchanger condition during operation. Differential pressure is monitored by taking daily readings, as well as by a dp alarm in the control room. Differential pressure provides an indication of the heat exchanger

condition that is qualitatively linked to each heat exchanger's heat transfer capability. Although the measured dp across the heat exchanger does not provide an all-inclusive indicator of heat exchanger performance, it does give a general indication of the combined effect of macrofouling and heavy scaling. Therefore, the dp measurement, with microfouling under control, is one indicator of overall heat exchanger functionality. Maintenance, surveillance testing, and inspections during cleanings are also other indicators.

EVALUATION OF CURRENT OPERATIONAL LIMITS ON MACROFOULING AND MICROFOULING

Continuous Chlorination

As the Inspection Report notes, PG&E has implemented a continuous chlorination program that is very effective and has significantly reduced the frequency of heat exchanger outages for cleaning. Prior to implementing continuous chlorination in 1992, various methods had been used at DCPP to control both micro- and macrofouling. Batch chlorination was in use at DCPP from late 1984 to mid-1991, although a few periods existed during this timeframe when equipment problems or system enhancement modifications precluded the use of chlorination. Both methods of chlorination can control the growth of macrofouling as well as microfouling, although continuous chlorination is a superior method. The control of macrofouling requires higher chlorine concentrations than the control of microfouling; however, DCPP continuously maintains sufficient chlorine in the ASW system to control both types of biofouling in the piping and the heat exchangers.

Since full implementation in 1992, the continuous chlorination system has operated effectively. However, to assure equipment availability for chlorination, Equipment Control Guideline (ECG) 17.2, "ASW Continuous Chlorination System," has been approved to provide administrative controls on the ASW chlorination system. This ECG specifies the length of time that the continuous chlorination system may be out-of-service without compensatory actions to control biofouling. In addition, the ECG includes a periodic surveillance requirement to verify that adequate chlorination is being performed.

Heat Exchanger Tube Cleaning, Scraping and Waterjet Cleaning

In accordance with Maintenance Procedure MP M-56.16, "Heat Exchanger Tube Cleaning," the heat exchanger tubes are mechanically scraped during each refueling outage (nominally every 18 months). Cleaning of the tubes with a waterjet has been performed periodically in the past during macrofouling cleaning (whenever the dp reaches its administrative limit), as discussed below.

Maintenance History and Observed Results

Without adequate controls during the proper oceanic conditions, microfouling of the tube side of the CCW heat exchanger can be a significant contributor to the reduction in heat exchanger performance. The average amount of microfouling

found at the time of cleaning has been as high as 7.9 9 (dry weight) in the tubes sampled. This was a peak result during an unusual period of high susceptibility to microfouling during which chlorination had been out of service for several months. Following the initiation of continuous chlorination, a more representative figure has been less than 1.0 g (dry weight) per tube. In addition, microscopic analysis of the material removed from the tubes after initiation of continuous chlorination indicates little organic material present (i.e., mostly sediment rather than biofouling). This indicates that the rate of biofouling and its subsequent impact on heat exchanger performance is being effectively controlled by the continuous chlorination program and the regular tube scraping during each outage. When controlled in this manner, microfouling and scaling will not have a significant impact on the heat transfer capability of the heat exchangers.

Historically, the frequency of heat exchanger cleaning prior to the initiation of continuous chlorination had been every four to six weeks. The current cleaning interval with continuous chlorination in service is approximately every six to eight months. The longer cleaning intervals are indicative of the lower rate of macrofouling due to the effectiveness of continuous chlorination.

EVALUATION OF GL 89-13 BASELINE HEAT EXCHANGER TEST RESULTS

The performance of the four CCW heat exchangers (the ratio of predicted heat exchanged under accident conditions versus design nameplate heat exchanged) was as follows. These results include the effects of as-tested macrofouling and microfouling including calcification and scaling.

COMPONENT	HEAT EXCHANGE RATIO
CCW 1-1 HX	1.080
CCW 1-2 HX	0.987
CCW 2-1 HX	1.112
CCW 2-2 HX	1.109

The results of the GL 89-13 testing on the CCW 1-2 heat exchanger indicated a heat transfer capability of 98.7 percent of the design value (97.5 percent after accounting for 1.2 percent uncertainty). A review of the 1990-1991 operating and cleaning history indicates that no chlorination was applied to any of the four CCW heat exchangers during the summer 1990 ocean upwelling and warming period, due to work being performed in the intake structure. However, the CCW 1-1, 2-1, and 2-2 heat exchangers had been cleaned of macrofouling and waterjetted more frequently than the CCW 1-2 heat exchanger during this time period. As a result, these CCW heat exchangers did not develop a microfouling layer equivalent to that of the CCW 1-2 heat exchanger. The CCW 1-2 heat exchanger was not waterjetted or scraped between the 1990 period of high potential microfouling until after the GL 89-13 test in February 1991. This is consistent with the high level of microfouling found in the 1-2 CCW heat exchanger at the time of the test. The CCW 2-1 and 2-2 heat exchangers were cleaned and batch chlorinated with a frequency typical of normal practices.

The average dry weight of the microfouling samples collected from the 1-2 CCW heat exchanger in February 1991 was 7.9 g. In contrast, the dry weight of samples collected from the 2-2 CCW heat exchanger in June 1991 and the 2-1 CCW heat exchanger in August 1991 (prior to their performance testing in September 1991) averaged 0.3 and 0.4 9, respectively.

PG&E believes that if the 1-2 CCW heat exchanger had been cleaned and waterjetted as frequently as the other CCW heat exchangers prior to the test, it would have performed similarly to the Unit 2 heat exchangers. However, in order to confirm this, additional testing will be performed on the heat exchangers during the upcoming Unit 1 and Unit 2 refueling outages.

In addition, PG&E requested HOLTEC, International to analyze the GL 89-13 test data for the CCW 1-2 heat exchanger. The HOLTEC model was specifically developed for GL 89-13 evaluation and has been widely used by the nuclear power industry. It has been validated using an approved software quality assurance program and has been used in audit responses; therefore, it is considered a good validation of the HTC-STX program. The preliminary results of the HOLTEC model reanalysis of the GL 89-13 test data predicted the CCW 1-2 heat exchanger performance at nameplate condition would be 101 percent with a 95 percent confidence level. At the ASW design basis specified in WCAP-12526, Rev. 1 condition, the preliminary result would be 100.3 percent with a 95 percent confidence level. For comparison, the HTC-STX results at the Yuba nameplate Condition were 98.7 +/- 1.2 percent and at the ASW design basis specified in WCAP-12526, Revision 1 condition, 98.0 +/- 1.2 percent. A January 1994 resolution of the uncertainty analysis resulted in lowering the overall uncertainty from 1.5 to 1.2 percent for the CCW 1-2 heat exchanger. This reanalysis confirmed the validity of the HTC-STX computer program.

EVALUATION OF EFFECTS OF ASW FLOW AND OCEAN TEMPERATURE ON ASW SYSTEM OPERABILITY

Two important key parameters, related to heat transfer capability, are the amount of ASW flow through the heat exchanger and the temperature of the ASW.

ASW Flow: ASW flow is affected by the number of pumps in operation, actual pump performance, tide level, and the cleanliness of the piping system, traveling screens, and the CCW heat exchanger.

ASW Temperature: Ocean temperature varies daily and seasonally. While the daily average ASW Fahrenheit temperature typically runs in the 50s, the average will occasionally rise into the low 60s.

ASW design basis heat removal capability is a function of ASW flow, heat transfer area, and temperature (with a fouling factor to account for the fouling mechanisms described above.) The ASW temperature and flow requirements interrelate to provide an equivalent peak heat removal capacity. For example, the heat removal provided by 1 0,7 50 gpm at 64 ° F is equivalent to the heat removal provided by 9,150 gpm at 58°F.

The CCW heat exchangers must be maintained in accordance with good industry practice for heat exchangers in seawater duty to assure that significant fouling or blockage does not occur. Sufficient ASW flow to meet design basis requirements must also be maintained. Assurance of adequate flow is provided by the performance of STPs M-26 and P-7B.

STP M-26 is performed monthly. The acceptance criteria for STP M-26 have been established based on curves in Westinghouse WCAP-12526, Revision 1, which provides the acceptable combinations of ASW flow and ocean temperature.

STP P-7B, "Routine Surveillance Test for ASW Pumps," is performed quarterly in accordance with ASME Section Xl to measure ASW pump flow and vibration.

The STP M-26 flow measurements have historically varied more than the STP P-7B flow measurements, even though both flow measurements are taken at the same ASW annubars. Recent flow measurements taken with Controlotron instruments and dye dilution tests show that the annubars appear to indicate less than the actual flow rate.

EVALUATION OF CURRENT OPERATIONAL LIMITS ON DIFFERENTIAL PRESSURE

The NRC Inspection Report identified Unresolved Item 50-275/93-36-03 relating to the technical basis for the high alarm setpoint established by PG&E for differential pressure (dp) across the heat exchangers. In particular, the Inspection Report stated that the alarm setpoint was set at 140 inches WG. Pursuant to an Operations Department standing order, cleaning of the heat exchangers is initiated when the differential pressure is about 130 inches WG. Based on the inspector's observations, a concern was expressed that the 140 inch WG setpoint was inconsistent with the amount of macrofouling experienced by the heat exchangers at a lower differential pressure, and therefore the potential existed that at levels below 140 inches WG a heat exchanger might be excessively fouled and outside its design basis. This observation was based upon the understanding by the inspector that the heat exchanger contained a total of 2 percent margin beyond design.

The following is an evaluation of the NRC concerns regarding the technical basis for the current differential pressure alarm setpoint:

Differential pressure is a diagnostic tool and cannot, by itself, quantitatively be used to determine operability (see PG&E letter DCL-88-215, dated September 13, 1988). This is based on a consideration of the uncertainties associated with any established dp limit. These uncertainties include: measurement errors in ASW flow, variation and uncertainty in heat exchanger clean dp levels, uncertainty and drift associated with dp instrumentation, and modeling uncertainties of actual pressure and flow losses that are associated with the heat exchanger design and macrofouling.

However, a dp setpoint can be used as a threshold indicator. When the established threshold is reached, the heat exchanger waterbox and tube conditions should be

inspected to assure that actual conditions in the heat exchanger are consistent with those assumed.

PG&E has established thresholds (limits) for the CCW heat exchangers. The limits have been established based on empirical evidence collected by PG&E biologists and engineers as to the actual amount of macrofouling observed in the heat exchanger channel head, and on the tube sheet, when the heat exchangers were removed from service for cleaning over the past nine years of operation. In addition, PG&E has developed a model of hydraulic pressure loss for the CCW heat exchangers which can be used to determine the reasonableness of the empirical evidence cited above. These sources of information are discussed below.

The dp setpoint at DCPP has changed over the years as new information has become available. Early in plant operation the setpoint was at 110 inches WG, a level which immediately caused operational problems. Inspection of heat exchangers in alarm at 110 inches WG indicated that the heat exchangers had little to no macrofouling at this level. PG&E moved the setpoint over the next several years in an attempt to find the optimal balance between cleaning the heat exchanger frequently enough to assure adequate heat transfer, and not cleaning the heat exchanger so often as to increase the overall risk to plant safety of having the heat exchanger out of service. PG&E established a two-tiered limit of a 130 inch WG cleaning criterion, coupled with a 140 inch setpoint at which the heat exchanger is declared inoperable and removed from service, based on the observed low level of fouling during heat exchanger cleanings at these limits of dp.

To further substantiate the empirical evidence and engineering judgment that established the two-tiered limit, PG&E developed a conservative model to estimate differential pressure losses across the CCW heat exchangers. A brief discussion of the concepts used in the PG&E differential pressure model follows.

The PG&E model assumes that dp consists of two components: hydraulic losses across the heat exchanger and differences in static head between the inlet and outlet waterboxes.

The hydraulic losses across the heat exchanger are composed of losses due to turbulence effects at the inlet/outlet of the tubes and waterboxes, and losses through the tubes themselves (including a slight increase in dp due to the tube inserts installed at the tube inlets). This component of measured differential pressure is a direct function of the velocity of the water passing through the heat exchanger and its tubes and thus is a function of the ASW flowrate. However, the velocity of water through the tubes is not only a function of the total ASW flowrate, but also the number of tubes available for flow. Thus, as tubes become plugged (e.g., due to blockage as a result of macrofouling), the hydraulic loss component for the dp increases.

The other component considered in the PG&E model is the difference in static head between the inlet and outlet waterboxes. As a result of testing performed in 1989, it was established that the inlet waterbox level was full. This same testing was

interpreted as indicating a void in the outlet waterbox of approximately 30 inches WG. The difference in waterbox level would be reflected in an increase in measured dp. Recent testing using ultrasonic measuring techniques has shown that the level in the outlet waterbox is being maintained at 5 2 inches of the top during operation with one pump aligned to one heat exchanger. The previously measured 30 inches is now attributed to a combination of both the water elevation differences and velocity losses in the outlet waterbox. Thus, the static head differential between the inlet and outlet waterboxes is assumed to be 5 inches instead of the previously assumed 30 inches. This reduces the contribution to measured dp due to waterbox voids.

CCW heat exchanger performance is a function of several variables: ASW flowrate, ASW temperature, and fouling. CCW heat exchanger performance increases with increasing ASW flow and decreasing ASW temperature. Heat transfer across the tubes is a function of the thermal resistance of the tube walls as well as the buildup of insulating materials on the tube surface (e.g., microfouling and scale). The available heat transfer area is a function of the number of tubes through which cooling water can flow. This is affected by macrofouling that may block flow through some of the tubes. As indicated above, this accumulation of macrofouling is reflected by an increase in dp measured across the heat exchanger. Preliminary analysis has shown that the negative impact on heat transfer of partially blocked tubes is smaller In magnitude than the negative impact of fully blocked tubes at equivalent dp levels.

PG&E then conservatively determined the extent to which available CCW heat exchanger margin was reduced as effective area of the heat exchanger was lost due to assumed macrofouling. PG&E used the margin available between design heat transfer capacity and the heat transfer capacity determined during the GL 89-13 testing using the Unit 2 data as a baseline. These test results demonstrated that the heat transfer capability for a clean heat exchanger was 109 percent (including uncertainty) of its design capacity. As discussed above, these Unit 2 data are the most representative of baseline CCW heat exchanger capacity. PG&E modeled increasing numbers of fully blocked tubes until the calculated reduction in heat exchanger performance was equivalent to its design capacity. These calculations showed that at nominal flow conditions, approximately 20 percent (246 if the tubes) could be fully blocked and the heat exchanger would still be able to reject the design heat loads. Combinations of higher ASW flow rates and/or lower ASW temperatures could allow even more tubes to be blocked. This process was repeated for a variety of ASW flow and ocean water temperature combinations since both factors independently influence available heat exchanger capacity. Once PG&E established the number of fully blocked tubes equivalent to a maximum allowable fouled condition, PG&E calculated a predicted associated increase in pressure drop. This predicted increase in pressure drop must be added to the baseline pressure drop of a "clean" (no tubes plugged) heat exchanger. Using this methodology, maximum allowable dp limits were predicted. The methodology utilized by PG&E has been reviewed in detail by an industry heat exchanger expert and found to be a reasonable modeling approach.

This methodology was then used to generate a family of curves for variouscombinations of ASW flow and ocean water temperature that would assure the CCW heat exchanger capability to remove the design basis heat load. Recent pump flow testing data have shown the calculated allowable dp is approximately 135 inches WG at 64° F for the most limiting pump and heat exchanger combination. Relaxing the conservatism in the model to allow some partially blocked tubes, thereby making the model more realistic, is expected to increase this maximum allowable dp above 140 inches WG. The remaining three heat exchangers in similar service showed allowable operating differential pressures in excess of 140 inches WG. These values correspond well to the dp limits currently in place at DCPP and reconfirm the adequacy of the current two-tiered dp control strategy. These calculations were conservatively based on 64° F ocean water temperatures. Even without accounting for partially blocked tubes, calculated allowable dps would be greater than 140 inches WG for all heat exchangers at ocean temperatures of 62°F and lower, which DCPP generally has experienced during its operating history. This model contains limitations such that it should be applied to heat exchangers where the "clean"baseline operating conditions are firmly established. Since this model has onlyrecently been developed, benchmark data have not been taken.

Notwithstanding, PG&E has taken the results from this model into consideration for the development of future ASW operating criteria. These criteria will be used to assess the condition of the CCW heat exchangers. Specifically, PG&E will maintain the following operating limits for the CCW heat exchangers:

- Consistent with PG&E's engineering judgment and evaluation of past empirical data and as generally confirmed by the analysis presented above, the high differential pressure alarm setpoint will be maintained at 140 inches WG.

- Based on the confirming information provided by conservative modeling, PG&E will maintain the cleaning criteria at 130 inches WG.

- To demonstrate heat exchanger cleanliness, regardless of dp, each heat exchanger will be inspected at a frequency of six months, and will be cleaned as required.

PG&E will maintain the described limits and inspection for the current operating cycles. Since PG&E will be performing functional tests of the CCW heat exchangers during the next refueling outages, PG&E will reassess, as appropriate, these limits based on the outcome of these tests.

In summary, these criteria, combined with the ongoing chlorination and maintenance programs, assure that the system will be capable of performing its design basis function.

ADDITIONAL OPERATIONAL AND MAINTENANCE PROGRAMS

With the combination of monitoring dp, surveillance testing, and additional operational and maintenance activities, the ASW system operability is assured. These additional activities, summarized in Table 1 below, include periodic preventive maintenance and inspections of the traveling screens, pump bays, expansion joints and piping coatings in the ASW flow path, monitoring and cleaning of the CCW heat exchangers as described above, and other STPs for the check valves and power actuated valves in the system.

TABLE 1
MAINTENANCE AND TESTING ACTIVITIES

Equipment/Parameters	Procedure/ Work Order	Frequency
Traveling Screen		
Corrosion/Damage	PM 41722	18 months
Pump Bays		
Corrosion/Debris	PM 52070	18 months
Pumps/Disch. Check Valves		
Flow/Vibration	STP P-7B	Quarterly
Expansion Joints		
Cracks/leaks	PM 40010	Annually
Power Actuated Valves		
Stroke Time	STP V-3F	Quarterly
Piping		
Flow	STP M-26	Monthly
Temperature	STP I-1 A	12 hours
Coating/Biofouling (Inspection)	STP M-235	6 years
Biofouling (Chlorination)	ECG 17.2	-
Heat Exchangers		
Flow	STP M-26	Monthly
Differential Pressure	PK01 -01	Continuous
Biofouling/Calcification	PM 53586	As needed
Biofouling (Chlorination)	ECG 17.2	-
Coating/Corrosion	PM 51872	18 months
Tube Cleaning/Scraping/Waterjet	MP M-56.16	18 months

EVALUATION OF PUMP RUNOUT

The NRC Inspection Report identified a concern regarding potential ASW pump runout under certain conditions. The concern had previously been identified in PG&E surveillance report SQA-93-0031.

"Runout" describes a condition of pumping higher flow rates than the pump's design performance curve. Specifically, runout concerns are associated with operating the ASW pump at high flow conditions such that cavitation, pump motor tripping, and/or pump overheating may occur. PG&E has reviewed its calculations, ASW pump testing results, and data from the pump manufacturer, and concluded that acceptable net positive suction head (NPSH) is available for the runout flow conditions, and that the associated brake horsepower (BHP) and temperatures will not jeopardize pump motor operation.

At ocean water temperatures of 64°F or greater, a second heat exchanger is placed in service to assure that sufficient heat transfer capability is available for design basis accident heat loads. It is for this configuration of one ASW pump supplying cooling water to two CCW heat exchangers that ASW pump runout is predicted.

The ASW pump runout concern was based on calculated flows using the highest measured flow reading of the STP M-26 test results. Given the test data and correcting it for the lilt limiting conditions (i.e., high and low tides, minimum flow resistance through the heat exchanger, and fully open CCW heat exchanger valves) with one pump supplying two heat exchangers, the predicted flows were 16,100 gpm and 15,100 gpm for high and low tides, respectively. This was determined by engineering personnel to not represent a challenge to the operability of the ASW system. A review of actual pump performance records determined that the predicted high flows could not be achieved with the existing equipment and system design configuration. Testing was also performed in 1989 for various configurations of the ASW system (TP TB-89C3), which provided additional data to support the judgment that the postulated runout conditions were not probable. A flow of 13,540 gpm and a brake horsepower of 439 HP were measured for one pump supplying two CCW heat exchangers.

The design calculation for the ASW system estimated flows of 15,100 gpm and 14,500 gpm for high and low tide conditions, respectively, when aligned with one pump supplying two heat exchangers. The design calculation addressing ASW pump NPSH requirements concluded that the NPSH available at a high tide exceeded the required NPSH by several feet; the NPSH available at low tide was below the required NPSH by approximately two feet. The low tide condition was determined to be acceptable, although minor cavitation may occur, based on the fact that the difference between the required and available NPSH is small and the operating condition would be of a short duration (until tide level increased within a few hours). Damage due to cavitation occurs over a long period of continual operation (months to years) in a condition of insufficient NPSH available.

Design evaluation of the maximum brake horsepower for the ASW pumps estimated the BHPs to be approximately 450 HP, over the range of operating design flows. This design value was also supported by information provided by the pump manufacturer, who stated that at a flow of approximately 13,000 gpm, the horsepower curve peaks at 450 HP and remains flat out to 15,000 gpm and beyond. However, it was anticipated that ASW pump operation may result in brake horsepowers that exceed the design maximum of 450 HP. As a result, further evaluation by the motor manufacturer concluded that the ASW pump motors are capable of operating at 465 HP without exceeding their design limits.

To confirm PG&E's conclusions regarding runout, plant test TP TB-9409, "ASW System, Test of Alternate Configurations," was conducted on February 4-8, 1994. The ASW pump and test data were evaluated and confirmed that cavitation and motor overheating/tripping are not a concern. The flow results correlated well with design calculations. Test flows were adjusted to design basis low tide conditions (-4.1 ft mean sea level) and, only the configuration of one pump supplying two CCW heat exchangers, where cavitation is predicted. The cavitation is judged to be minor and acceptable for operation because of the minimal difference between available and required NPSH, and the short duration of the extreme low tidal condition. The tests confirmed that the ASW pump motors may operate at brake horsepowers in excess of 450 HP with a maximum of less than 465 HP for the design operating conditions. The test results also confirmed that the motor bearing and stator temperatures would remain within their design basis limits.

PG&E consulted the ASW pump manufacturer and an independent pump expert on the impact of operating the ASW pumps in a condition where the NPSH available was less than the required amount. It was their judgment that the pump will continue operating; however, there may be a slight drop in performance at the point where the required NPSH for the flow was not available. This operating condition would result in cavitation, and eventual impeller and pump damage if operated continually over a long period of time (months to years). The impact of the cavitation at the postulated condition was determined to be of very low consequence since low NPSH margin occurs only at low tide conditions in the one pump, two heat exchanger configuration. It was also determined that the impact of operating at higher flows with cavitation would not result in a significant, if any, increase in BHP requirements since the pump performance would begin to drop off. Engineering calculations will be revised to incorporate the results from test TP TB-9409.

In summary, PG&E has evaluated the potential for ASW pump runout and concluded that it will not affect the capability of the system to perform its design function. This conclusion is based on actual testing, pump and motor manufacturers' information, and engineering calculations.

CONCLUSION REGARDING CURRENT ASW SYSTEM OPERABILITY

The CCW heat exchangers are capable of meeting their design basis requirements when maintained in a clean condition and operated within design basis parameters.

PG&E's current maintenance, operational, and testing programs for the heat exchangers assure that they will continue to be maintained sufficiently clean of macrofouling and microfouling to allow them to perform their design basis function. Based on the above evaluation, the ASW system is operable and will continue to perform its intended safety function.

ENCLOSURE 2

PRELIMINARY SAFETY EVALUATION OF PAST OPERABILITY OF ASW AND CCW SYSTEMS

Introduction

As described in Enclosure 1, key parameters affecting the performance of the ASW and CCW systems include: macrofouling and microfouling, ASW flow, and ocean temperature. An extensive review of historical maintenance, testing, operational, and biological factors was performed to identify time periods with a high potential for macrofouling and microfouling. During this review of past operation, specific periods of time have been identified during which one or more of these key parameters may have been outside current acceptance criteria. These time periods, and the safety significance of the associated fouling, are discussed below.

Biological Fouling Conditions

The potential for significant microfouling of CCW heat exchanger tubes occurs when certain conditions are met. These conditions include:

- An upwelling of cold, nutrient-rich water from deep ocean layers, which occurs as a result of strong northwesterly winds that characteristically blow during the spring.

- A period of high ocean temperatures, which, following an upwelling period, allows the microorganisms to "bloom." Experience indicates that ocean temperatures of approximately 58°F or greater must be reached over a several week period for the "bloom" to occur.

- The chlorination system is out-of-service for a considerable period prior to and during the "bloom." Without chlorination during the "bloom" period, microfouling could form on the tubes of the heat exchanger. If chlorination is restarted after the "bloom" has occurred, further microfouling is stopped. However, residual material placed by the microorganisms remains in the tubes as a coating and continues to impact heat exchanger performance. Once deposited, waterjetting or scraping of the tubes is needed to remove the residual material.

Bounding Microfouling Condition

PG&E's evaluation of maintenance and operational practices over Diablo Canyon's operating history indicates that the bounding conditions for potentially significant

microfouling only occurred during July and August of 1990. Prior to this period, upwelling of nutrients had occurred and was followed by a period of ocean warming. As a result, a microfouling "bloom" occurred. PG&E's analysis indicates that microfouling reached significant levels in July 1990 as ocean temperature exceeded 58°F. In addition, the chlorination system was out-of-service during this period while PG&E was replacing cast iron piping in the system. When batch chlorination was restored on August 21, 1990, further microfouling ceased. However, the residual material from the microorganisms remained in the CCW heat exchanger tubes until waterjetting or tube scraping was performed. PG&E's review indicates that there were no other time periods when the lack of chlorination and maintenance was coupled with favorable environmental conditions for microfouling.

Of the four CCW heat exchangers, the 1-2 heat exchanger was the most susceptible to microfouling based on its chlorination, maintenance, and operating history. The remaining three heat exchangers received waterjet cleanings between the period of high microfouling potential and the performance of the GL 89-13 performance testing. In addition, two of the other three heat exchangers were operated less frequently during the period of high microfouling potential.

The CCW 1-2 heat exchanger was not waterjetted or scraped during the period from August 1990 until after the performance of the GL 89-13 performance test in February 1991. PG&E believes that the heat transfer microfouling characteristics of the CCW 1-2 heat exchanger during its associated GL 89-13 testing represent the bounding microfouling case.

PG&E evaluated the highest macrofouling that may have existed coincident with high microfouling. During August 1990, the CCW 1-2 heat exchanger was taken out of service for cleaning with a recorded dp of 130 inches. It was not again taken out of service until the test in February 1991, at which time the recorded dp was 1 10 inches. Thus, the August 1990 dp of 130 inches represented the highest macrofouling reached during this bounding microfouling period. The level of macrofouling associated with a dp of 130 inches, coupled with an assumed level of microfouling found during the testing of the CCW 1-2 heat exchanger, represents the most limiting fouling of a CCW heat exchanger.

Bounding Macrofouling Condition

PG&E's review of macrofouling data identified periods of operation at an elevated dp (greater than 140 inches). The historical data focused attention on a period from August 1986 to March 1988. The apparent bounding case of macrofouling identified in this period occurred on November 8, 1987, when CCW 1-2 heat exchanger was removed from service with a dp of 170 inches in conjunction with an ocean water temperature of 61° F. A review of environmental conditions associated with this period of high dp determined that coincident conditions required for significant microfouling did not exist. PG&E believes that microfouling levels at that time were consistent with the levels observed during the Unit 2 CCW heat exchanger GL 89-13 tests.

PG&E has evaluated this condition of high macrofouling. Based on the available information, PG&E's evaluations have determined that the bounding conditions of high macrofouling were not as limiting as the conditions which existed in August 1990. Thus, the condition of high microfouling with a 130 inch dp is the bounding fouling case.

Safety Significance

PG&E has analyzed the bounding case for high microfouling coincident with a 130 inch dp as described above for safety significance. These analyses were performed using the old Westinghouse Mass and Energy (M&E) release model, which is the licensing basis for DCPP. Additionally, a newer more realistic Westinghouse M&E release model with a methodology licensed for use at other Westinghouse plants was used with best estimate values and other realistic inputs for certain parameters. This model more accurately reflects the physical phenomena that occur. Although not licensed for use at DCPP, this new model can be used to determine the M&E releases expected for the current and past plant configuration.

The impact of bounding case fouling on the containment integrity analyses was performed by Westinghouse using the old "current licensing basis) M&E release model. Westinghouse evaluated the design basis LOCA as well as the limiting MSLB accidents for impacts on containment pressure and temperature. The conclusion of these evaluations is that the containment design basis pressure and temperature would not have been exceeded during a postulated LOCA or MSLB.

The design basis CCW temperature limits allow a transient temperature maximum of 132° F for 20 minutes. The temperature limit for continuous operation is 120° F. PG&E has evaluated the impact of the bounding case fouling on the limiting post-LOCA CCW temperature transients. Using the old (current licensing basis) M&E release mode, PG&E and Westinghouse have determined Hat the peak CCW temperature may have exceeded the design basis CCW temperature during the injection phase following a LOCA.

Westinghouse then performed an analysis of the containment temperature transient following a LOCA using the new, more realistic M&E release model. The results of these analyses were used by PG&E to evaluate the CCW temperature transient that would result from the containment conditions calculated by Westinghouse using the new M&E release modeling methodology. These evaluations concluded that the CCW temperature remains below design limits during the injection phase of the accident, but could have exceeded its design basis temperature limits in recirculation for an extended period if operator action is not taken.

The potential for the CCW system to overheat during the post-LOCA recirculation phase of an accident was previously identified by PG&E in 1991. LER 1-91-018, "Component Cooling Water System Outside Design Basis," reported that the heat load during cold leg recirculation may exceed the CCW system design basis temperature limits. Specific recirculation transient analyses were not performed. At

that time it was reported that operator action to keep CCW temperatures within design limits was required if the two ASW pump/two CCW heat exchanger configuration could not be established. The safety significance conclusions regarding the bounding case of fouling are similar to those reported in LER 1-91-018. Guidance to address conditions when both ASW pumps and CCW heat exchangers were not available was incorporated into step 3.d of EOP E-1.3, "Transfer to Cold Leg Recirculation," in response to the LER. The potential for elevated CCW temperatures identified above is due primarily to the heat loads that were imposed on the system during recirculation, and not specifically caused by the identified heat exchanger fouling. Preliminary analysis has indicated that, had this EOP guidance been in place at the time that the bounding conditions existed, the CCW system temperature, using the new M&E release model, would have remained within its design basis.

To bound the conditions in place during the 1990 high macrofouling and microfouling case, as well as the 1987 high macrofouling case, PG&E evaluated the CCW temperature transient assuming likely operator actions prior to revising the EOPs even though more timely operator actions were in place for the 1990 case. Prior to the 1991 revision of EOP E-1.3, EOP E-0, "Reactor Trip or Safety Injection," was revised in 1989 to require placing a second CCW heat exchanger in service when only one ASW pump is available (post-LOCA). PG&E developed a timeline of actions which while not formally proceduralized, are believed to be representative of those actions that would have occurred prior to the 1989 EOP changes. The timeline would have operators secure two CFCUs 15 minutes after the start of recirculation in response to high CCW temperature alarms and subsequently place the second CCW heat exchanger into service 10 minutes later. This timeline bounds both the 1990 and 1987 cases.

Assuming operator action as described above, the limiting CCW temperature transient was evaluated for the bounding 1990 high micro- and macrofouling case. The peak CCW temperature based on this scenario was approximately 136° F and the cumulative time above 120° F was approximately 50 minutes. The impact of the elevated CCW temperatures on the components of the vital CCW headers was evaluated. Westinghouse analyzed the impact of the CCW temperature profile and has determined that the Sl and RHR pumps and the CFCU fan motors would perform their design basis function. The CCW pump manufacturer confirmed that the CCW pumps would perform their design basis function at the elevated CCW temperatures. The post-LOCA sampling system may have been temporarily disabled by the elevated CCW temperatures. However, the ability to assess core damage remained available from alternate proceduralized means. The centrifugal charging pumps (CCP) cannot be shown to continue to be available at these elevated temperatures although the exact point of failure is not known. However, the CCPs are available for the entire injection phase of the accident. Regardless of the CCPs availability for recirculation phase, Westinghouse and analyses have determined that during the recirculation phase, other ECCS pumps are available to perform required ECCS functions.

Based on the foregoing detailed analysis of this event, PG&E concludes the following:

- The fouling identified on the CCW heat exchangers would not have resulted in the containment design pressure or temperature being exceeded.

- The CCW design basis temperature limits would only have been exceeded during post- LOCA recirculation.

- Considering the CCW temperature transient, containment and core cooling functions would not be significantly affected. All vital components served by the CCW system would have continued to perform their design basis function, or redundant equipment would have been available to perform these functions.

Accordingly, this event had no safety significance and the health and safety of the public would not have been affected.

ENCLOSURE 3

PG&E'S RESPONSE TO NRC INSPECTION REPORT NOS. 50-275/93-36 AND 50-323/93-36

NRC Inspection Report Nos. 50-275/93-36 and 50-323/93-36 identified a number of NRC concerns and open, follow-up, and unresolved items regarding past and future operability of the ASW system and PG&E's implementation of controls to assure continued ASW system operability. PG&E's response to each of these items in the Inspection Report is provided below.

NRC Inspection Report Follow-up and Unresolved Items

NRC Follow-up Item 93-36-01 noted that the ASW system flow test acceptance values did not include a simple value for minimum flow, but provided a series of curves dependent on the ocean and CCW temperatures. The inspection noted that PG&E stated the test acceptance values were derived from a Westinghouse study, CAP-1252G, Revision 1, Auxiliary Salt Water and Component Cooling Water Flow and Temperature Study for Diablo Canyon Units 1 and 2," dated June 1992. The study is one of three different design bases described in PG&E's design criteria memorandum, DCM No. S-17B, Revision 2, "Auxiliary Saltwater System." The inspection noted that PG&E had indicated that the revised design bases had not been reviewed by the NRC technical branches. The inspection records stated that acceptability of PG&E's revised design bases is considered an open item.

PG&E Response

The original design basis for the ASW system was provided by Westinghouse. This design basis required the ASW system to remove a post-LOCA heat load of 252 X 106 Btu/hr. The heat load was based upon maximizing containment pressure by assuming the loss of a vital electrical bus which causes a loss of power to two CFCUs. This scenario yielded conservative containment LOCA pressures.

In 1983, a scenario was determined to be more limiting to the ASW system heat load. This scenario assumed that during a LOCA no vital bus failure occurred, but assumed the active failure of an ASW pump. In this scenario, the maximum post-LOCA heat load is transferred to the five CFCUs and then to the ASW system through the COW heat exchangers. This maximum heat load is 325 X 106 Btu/hr. Since 1983, this transient has been recognized as the Diablo Canyon design basis for the ASW system as noted in NRC SSER 16. PG&E has not changed this design basis.

The Westinghouse study in WCAP-12526, Revision 1, does not change the ASW heat load design basis. This WCAP provides equivalent heat removal using ASW flow and seawater temperature as variables.

Actions Being Taken

PG&E will review the current ASW basis with the NRC technical staff.

NRC Unresolved Item 93-36-02 noted an apparent failure to provide complete and accurate information to the NRC regarding the ability of the CCW 1-2 heat exchanger to meet the design basis heat load.

PG&E Response

Summary

In regard to the Inspection Report's concerns with the accuracy and completeness of information provided by PG&E in response to GL89-13, PG&E is committed to the highest levels of accuracy and credibility in the information it provides to the NRC and the public, and takes very seriously any issue raised relating to this commitment. Based on its comprehensive review of all relevant documents and information, PG&E believes that its statement regarding the results of heat exchanger performance testing was accurate and complete when considering the guidance in the GL, as well as the previous information PG&E had provided the NRC regarding the limitations and inconclusiveness of such testing. However, PG&E agrees that its engineering evaluation of the test results should have been more comprehensive.

At the time PG&E letter DCL-91-286, dated November 25,1991, was submitted, PG&E believed that its statements were accurate and complete. GL 89-13, and Supplement 1, provided guidance regarding the level of detail required in licensee responses (see GL 89-13, Supplement 1, Questions and Answers l.C.1 and III.C.2). PG&E believes that its response was consistent with this guidance particularly when considered in context with information that PG&E had provided the NRC in PG&E letter DCL-90-027, dated January 26,1990, regarding the limitations and inconclusiveness of the heat exchanger testing.

PG&E consulted an industry heat exchanger expert and further evaluated the CCW 1-2 heat exchanger testing results. PG&E now concludes that testing results did not meet design basis heat transfer requirements when analyzed using the Heat Transfer Consultants Inc., HTC-STX computer program due to the effects of microfouling at the time of the CCW 1-2 heat exchanger test. Based on the analysis presented in Enclosure 1, if the CCW 1-2 heat exchanger had been cleaned of microfouling prior to the conduct of the test, the heat exchanger would have passed. Current chlorination, maintenance, and operating practices assure the cleanliness of all CCW heat exchangers.

Background

NRC GL 89-13, Item 2, recommended that a test program be developed to verify the heat transfer capabilities of safety-related heat exchangers cooled by service water. It also indicated that an alternative acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing. PG&E'S response to GL 89-13 relied predominantly upon the established maintenance program, but heat transfer tests were performed to establish baseline heat exchanger nominal performance.

During the evaluation of the testing results, PG&E used an industry computer program, HTC-STX, to perform the analysis. The computer model predicted that CCW 1-2 heat exchanger was performing at 1.3 percent less than the design (nameplate) heat transfer capability. However, the 1.3 percent difference was judged to be within the range of the heat balance and measurement accuracy. Since all three of the other CCW heat exchangers exceeded their design heat transfer capability and all four CCW heat exchangers were designed similarly, PG&E concluded all four of the heat exchangers would meet their design basis requirements. This conclusion also appeared consistent with the guidance in GL 8913, which recognized the inherent limitations of baseline testing programs.

Recently, HOLTEC International was contacted to reanalyze the CCW 1-2 heat exchanger test data. HOLTEC is a qualified supplier of engineering services to PG&E, and HOLTEC indicated that their computer code has been validated. The preliminary analysis demonstrated that using the HOLTEC model the CCW 1-2 heat exchanger operated at 101 percent of design nameplate rating at the time of the test with a 95 percent confidence level.

For these reasons, the statement in DCL-91-286 factually reflected PG&E's engineering judgment at the time and was accurate and complete.

In retrospect, PG&E should have been more thorough in its analysis of the test results and should have documented the basis of accepting the CCW 1-2 heat exchanger test results. Consultation with an industry heat exchanger expert, who has worked previously on service water systems, has shown that: (1) the tests PG&E performed were generally well conceived and produced results of higher accuracy than PG&E believed possible at the time; (2) the test model used was more conservative in its results than the HOLTEC computer model used by the industry for similar GL 89-13 tests; and (3) the performance of the CCW 1-2 heat exchanger was due to biological microfouling present at the time of testing.

Actions Being Taken

PG&E is taking the following actions to assure that test results are comprehensively evaluated and regulatory submittals provide sufficient explanatory information.

1. Procedure AD1.ID1, "Format, Content and Style of Procedures," was revised subsequent to the performance of the GL 89-13 heat exchanger testing to require that comprehensive acceptance criteria be documented for special tests. Procedure AD13.ID1 3.1D1, "Conduct of Plant and Equipment Tests" will be further enhanced to require that deviations from acceptance criteria be documented and justified prior to acceptance of the deviation.

2. Design engineering, system engineering and licensing personnel involved with the GL 89- 13 testing, analysis, and submittal preparation will be counseled on the thoroughness that must be applied when engineering judgment is used to justify acceptance of test deviations.

3. A case study describing the situation, communications, corrective actions, and management's expectations on the events surrounding the ASW heat exchanger testing will be conducted with appropriate NPG personnel. The Directors of System Engineering, Mechanical Engineering, and Site Quality Assurance will present the case study. PG&E believes that by using the Directors to lead the case study, a clear message of expectations on the high standards of thoroughness, clear communication, and delineation of responsibilities will be fully reemphasized to the technical staff.

NRC Unresolved Item 93-36-03 noted an apparent failure to establish adequate dp limits to ensure CCW heat exchanger operability.

PG&E Response

Enclosure 1 provides a detailed description of the PG&E analysis which confirms the engineering judgment and empirical observations used by PG&E to establish current CCW heat exchanger dp setpoint limits.

Actions Being Taken

Upon completion of additional heat exchanger performance tests scheduled for 1R6 and 2R6, PG&E will reevaluate the dp setpoint.

Enhanced ASW flow instrumentation will be installed with local readouts.

ECG 17.2 has been approved to provide administrative controls on the ASW chlorination system.

In addition to inspections performed when dp limits are reached, each heat exchanger will be inspected at a frequency of six months and cleaned as required

NRC Unresolved Item 93-36-04 notes an apparent failure to develop a routine inspection program for the ASW system piping by the end of the fourth refueling outages, as committed to the NRC, and an apparent failure to provide accurate implementation status of the program in a letter to the NRC.

PG&E Response

Summary

PG&E agrees that a permanent procedure was not in place for periodically inspecting the ASW system piping at the time of the NRC inspection. However, a temporary procedure had previously been issued for the initial inspection conducted during 1 R4 and 2R4. In addition, an Action Request (AR) was tracking the completion of the final procedure prior to performance of the next inspection scheduled for refueling outages 1 R8 and 2R8. The surveillance procedure for piping inspection was issued on January 12, 1994, prior to its scheduled issuance date of June 1, 1994.

Background

GL 89-13 recommended establishment of a routine inspection and maintenance program for the ASH' piping and components so that corrosion, erosion, protective coating failure, silting, and biofouling would not degrade the performance of safety-related systems. PG&E letter DCL-90-027, dated January 26, 1990, indicated that procedures would be established by 1R4 and 2R4 for a routine inspection and maintenance program for the ASW system. The letter also indicated that the appropriate interval for the performance of these inspections would be determined based on 1R4 and 2R4 observations.

PG&E conducted ASW system piping inspections during the 1 R4 and 2R4 refueling outages. The piping inspections determined that the ASW system pipe lining was in excellent condition and capable of meeting its function as a protective barrier.

PG&E performed the 1R4 and 2R4 ASW piping inspections using temporary procedure TB-9048, "ASW Piping Inspection." The inspection found little macrofouling on the piping. Based on the results of the piping inspections, PG&E determined that the inspection frequency should be every fourth refueling outage. Conversion of the temporary procedure, TB-9048, into an STP with a reinspection frequency of every fourth refueling outage was being tracked by ARs. This is consistent with PG&E's practice for new maintenance and surveillance programs.

Actions Taken

To eliminate the concern regarding issuance of the inspection procedure, STP M-235, ASH Piping Inspection," was issued on January 12, 1994.

NRC Follow-up Item 93-36-05 noted that the previous PG&E review of the design basis did not identify several important design basis issues. An evaluation of the need to reperform an assessment of the adequacy of the design basis for the ASW system is a follow-up item.

PG&E Response

Summary

The evaluation of the capability of the ASW system to meet its design basis is provided in Enclosure 1.

Actions Being Taken

1. Additional CCW heat exchanger performance tests on both units will be performed to verify the adequacy of operational and maintenance practices to assure that the CCW heat exchangers meet design basis requirements. The tests will be conducted during the 1R6 and 2R6 refueling outages and will include dp measurement.

2. Part Integrated Problem Response Team (PRT) will be conducted on the ASW, CCW and interfacing systems by the end of 1994. This IPRT will thoroughly and critically review these systems. Membership of the IPRT will include operations, quality services, maintenance, Westinghouse, and engineering personnel. Based on the results of the IPRT, DCM S-1 7B will be revised to provide additional information on ASW system heat removal capacity.

NRC Unresolved Item 93-36-06 notes the apparent failure of PG&E to promptly resolve conditions adverse to quality, in particular the failure of PG&E's engineering organizations to resolve several Site Quality Assurance (SQA) surveillance findings in a timely manner.

PG&E Response

Summary

PG&E agrees that resolution of the SQA surveillance findings was not as thorough or comprehensive as PG&E management would expect. PG&E believes this stems from a failure of the organization to clearly focus on the operability consequences of issues raised in the SQA surveillance. As a result, appropriate priority was not placed on resolving the SQA issues by the responsible technical departments. This was not, however, a case where the surveillance issues were "dropped" by either SQA or the technical organizations. Significant follow-up activities occurred subsequent to the performance of the SQA surveillance in an attempt to bring issues raised to appropriate resolution. In addition to capturing unresolved issues in ARs, numerous phone calls, electronic-mails, and face-to-face meetings took place between SQA and responsible technical organizations. Twenty-one individual AR entries and eighth electronic mails were sent between SQA and the engineering Organizations on surveillance issues. The surveillance issues were the subject of discussion at two ASW system team meetings in early December 1993. Numerous undocumented contacts (phone calls, discussions, etc.) occurred between the responsible organizations. The Manager of Nuclear Quality Services met with the SQA Director and lead auditor in early August to discuss the status of responses to the surveillance. At this meeting, the Manager instructed that a schedule be established for resolution of the issues. The SQA staff and line organizations subsequently met in August and agreed to a December 31, 1993, completion schedule to resolve the technical issues. In addition, the Manager of Nuclear Quality Services raised the surveillance findings as an issue at the Nuclear Technical Services Emerging Issues meeting in San Francisco in August and November 1993 and also raised the issue at the DCPP Plant Manager's staff meeting to request that attention be placed on the surveillance response. However, despite the communication occurring on the issue, PG&E management personnel lost focus of the potential operability impact of the issues.

The delay in recognizing the potential operability implications of the SQA surveillance is in contrast with PG&E's demonstrated ability to thoroughly assess operability issues using procedure OM7.ID8, "Operability Evaluations," when presented with clear operability issues such as hardware failures or 10 CFR Part 21 notifications. In response to the SQA surveillance, PG&E technical organizations continued to conclude that the SQA surveillance issues did not represent current operability concerns. This was based on engineering judgment that existing maintenance and chlorination programs, described in response to GL 89-13, effectively assured current ASW system operability. The PG&E technical organizations, therefore, did not consider it necessary to enter OM7.ID8 to assess operability. The events were

exacerbated by a failure to take adequate ownership for resolution of the concerns, particularly at the Director and Senior Engineer levels within NPG. This led to a situation where periodic dialogue was occurring at the technical staff level but issues were not being fully resolved. Management inquiries as to what problems existed and what progress was being made were answered with responses that a technical resolution was proceeding.

As discussed in Enclosure 1, PG&E's subsequent evaluation demonstrated that (1) the dp setpoint is acceptable; (2) the ASW system has been operable since PG&E's implementation of GL 89-13; and (3) any untimeliness, therefore, did not adversely affect the public health or safety.

On December 15, 1993, a Prompt Operability Assessment was issued to document operability of the ASW system. In addition, a Nonconformance Report was issued to further investigate and resolve this concern. OE 93-16 was issued on December 30, 1993, to provide further justification for ASW system operability.

PG&E engineering has subsequently provided comprehensive evaluation of the operability issues raised in the SQA surveillance.

To prevent recurrence of these events, PG&E will establish specific procedural guidance on the maximum three PG&E will allow staff level personnel to evaluate questions involving potentially degraded structures, systems, and components before the issue becomes a quality problem and is elevated to upper management as an operability issue for prioritization and resolution. Appropriate technical staff will be trained and counseled on these management expectations. PG&E engineering management will also use outside experts, as appropriate, to help resolve technical issues that are at impasse and thus assure timely resolution.

Actions Being Taken

PG&E is taking the following corrective actions:

1. PG&E will establish an Interdepartmental Administrative Procedure to resolve issues that raise questions regarding operability. The key elements will be: (1) address any issue of immediate operability concern using procedure OM7.ID8; (2) generate a Quality Evaluation (QE) for issues that are not a clear, immediate operability concern, if the issue remains unresolved for 30 days; (3) establish firm completion dates within the QE; (4) place issues exceeding these completion dates on an "Operability Concerns List;" (5) review the Operability Concerns List at the NPG Officers/Managers weekly meeting; (6) assign specific responsibilities for resolution of Operability Concerns List items at the weekly meeting; and (7) review progress on assigned issues as identified by the Manager of Nuclear Quality Services.

2. A Human Performance Evaluation System (HPES) study will be performed. As part of the case study evaluation of the events of GL 89-13 testing, a

preliminary HPES study has been completed and identified the following items to be included in the case study discussion:

- The need for continuing vigilance in the depth and comprehensiveness of independent technical reviews of engineering evaluations and NRC licensing submittals.

- The need for clear test acceptance criteria for special tests and documentation of results and deviations.

- The need for enhanced supervisory oversight of engineering evaluations that relate to potential operability concerns.

- The need for improved teamwork and communication between departments on issues relating to operability or quality concerns.

- The need for a questioning attitude on design basis issues that potentially affect the operability and margins for safety-related systems, structures, and components by all personnel including design engineers, system engineers, maintenance personnel, and operators.

3. An HPES follow-up evaluation will be performed to determine the effectiveness of the case study discussion on assuring that management expectations are clearly understood and followed by the technical staff.

4. As was previously indicated in the Inspection Report response, appropriate technical personnel will be counseled on the need for thoroughness, completeness, and objectivity when analyzing questions that could impact operability.

5. Industry experts will be consulted, as appropriate, to provide resolution of technical issues at impasse.

NRC Unresolved Item 93-36-07 noted failure to use a validated computer code to predict design basis heat transfer capacity during heat exchanger capacity testing.

PG&E Response

Summary

PG&E believes that the computer program used for evaluation of the heat exchanger testing results met the guidance provided in GL 89-13.

Background

GL 89-13, Supplement 1, provided the results of workshops held between the NRC and interested parties to clarify the requirements of GL 89-13. The response to question III.A.12 in GL 89-13, Supplement 1, on heat transfer testing indicated that off-the-shelf software that is reviewed for technical adequacy is acceptable to the NRC.

Heat Transfer Consultants Inc.'s "Shell and Tube Heat Exchanger Design and Rating Program" (HTC-STX) was the computer program used to predict the ASW heat exchanger performance at design basis conditions. This program is a design, rating, and evaluation model for shell and tube heat exchangers. In March 1991, the HTC-STX model was benchmarked against the results of Yuba's heat exchanger design. The difference between the heat transfer coefficient given by Yuba and that calculated by the model was 2.6 percent, with the model predicting higher performance. In conversations with Yuba, they indicated that they incorporated a 2 percent margin into their design. Consequently, in 1991 the comparison between the actual Yuba design and PG&E'S model was actually 0.6 percent, which is excellent agreement. Based on these comparative results, PG&E'S benchmark provided sufficient verification that the model could be used and the results accepted.

In response to this unresolved item, PG&E recently performed two independent calculations to demonstrate that the model is valid. PG&E contacted Heat Transfer Consultants, Inc. to obtain their theoretical formulation of the heat transfer coefficient. An independent calculation was performed to evaluate the test fouling and predicted heat exchanger performance. These results demonstrate the validity of the computer program.

In addition, PG&E requested HOLTEC, International to analyze the GL 89-13 test data for the CCW 1-2 heat exchanger. The HOLTEC model was specifically developed for GL 89-13 evaluation and has been widely used by the nuclear power industry. It has been validated using an approved software quality assurance program and has been used in audit responses; therefore, it is considered a good validation of the HTC-STX program. The preliminary results of the HOLTEC model reanalysis of the GL 89-13 test data predicted the CCW 1-2 heat exchanger performance at nameplate condition would be 101 percent with a 95 percent confidence level. At the ASW design basis

specified in WCAP 12526, Rev. 1 condition, the preliminary result would be 100.3 percent with a 95 percent confidence level. For comparison, the HTC-STX results at the Yuba nameplate condition were 98.7 +/- 1.2 percent and at the ASW design basis specified in WCAP-12526, Revision 1 condition, 98.0 +/- 1.2 percent. A January 1994 resolution of the uncertainty analysis resulted in lowering the overall uncertainty from 1.5 to 1.2 percent for the CCW 1-2 heat exchanger. This reanalysis confirmed the validity of the HTC-STX computer program.

NRC Follow-up Item 93-36-08 noted a concern regarding the effect of calcification (on the inner surface of heat exchanger tubes) on the heat exchanger capacity and the potential effect of undetected tube plugging at the outlet.

PG&E Response

PG&E believes there is very low potential for undetected tube plugging. Tube plugging would be detected by heat exchanger dp. If significant calcification occurs, dp will increase and heat exchanger cleaning would be necessary. If tubesheet cleaning of macrofouling does not effectively reduce dp, PG&E's maintenance organization would use effective mechanical cleaning methods to eliminate calcification and return the heat exchanger to service.

Action Being Taken

PG&E agrees that trending of the dp increase on each CCW heat exchanger would be useful in anticipating calcification and other buildup that may affect dp. Consequently PG&E will revise STP M-26 to require a formal trending program to monitor this parameter.

Pacific Gas and Electric Company 77 Beale Street, Room 1451 Gregory M Rueger
PO Box 770000 Senior \'ice President and
San Francisco, CA 94177 General Manager
415/973-4684 Nuclear Power Generation
Fax 415/973-2313

March 8, 1994

PG&E Letter DCL-94-049

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

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Licensee Event Report 1-93-012-01
Auxiliary Saltwater System Outside Design Basis Due to Fouling

Gentlemen:

Pursuant to 10 CFR 50.73(a)(2)(ii)(B), PG&E is submitting the enclosed revision to Licensee Event Report 1-93-012-00 concerning the auxiliary saltwater (ASW} system being outside its design basis due to fouling. This revision is being submitted to report the results of a comprehensive evaluation of the past capability of the ASW system to meet its design basis. This revision provides the safety significance, root cause, and corrective actions.

PG&E's comprehensive evaluation concluded that this event had no safety significance and that the health and safety of the public were not affected.

Sincerely,

Gregory M. Rueger

cc: Mary H. Miller
Kenneth E. Perkins
Sheri R. Peterson
Diablo Distribution
INPO

DCO-93-EN-N022

Enclosure

6398S/DPS/2246

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Diablo Canyon Unit 1	0 5 0 0 0 2 7 5	1 OF 15

TITLE (4) AUXILIARY SALTWATER SYSTEM OUTSIDE DESIGN BASIS DUE TO FOULING

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MON	DAY	YR	YR	SEQUENTIAL NUMBER	REVISION NUMBER	MON	DAY	YR	FACILITY NAMES	DOCKET NUMBER (S)
12	30	93	93	- 0 1 2 -	0 1	03	08	94	Diablo Canyon Unit 2	0 5 0 0 0 3 2 3
										0 5 0 0 0

OPERATING MODE (9)	3
POWER LEVEL (10)	0 5 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11)

x 10 CFR 50.73(a)(2)(iv)

OTHER -

(Specify in Abstract below and in text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

	TELEPHONE NUMBER	
	AREA CODE	
DAVID P. SISK - SENIOR REGULATORY COMPLIANCE ENGINEER	805	545-4420

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
[ ] YES (If yes, complete EXPECTED SUBMISSION DATE)	[x] NO				

ABSTRACT (16)

On December 30, 1993, at 1150 PST, with Unit 1 in Mode 3 (Hot Standby) at 0 percent power and Unit 2 in Mode 1 (Power Operation) at 100 percent power, PG&E determined that the auxiliary saltwater (ASW) system and its associated component cooling water (CCW) heat exchangers for both units may not have met their design basis for certain time periods prior to implementation of continuous chlorination. Continuous chlorination was fully implemented in September and November 1992 for Units 1 and 2, respectively. This condition was reported to the NRC as a one-hour, non-emergency report in accordance with 10 CFR 50.72 (b)(1)(ii)(B) at 1150 PST on December 30, 1993.

The cause of this condition was an inadequate understanding of the effects of fouling on the CCW heat exchangers.

The ASW systems for both units currently are operable given the present maintenance, operational, and testing activities. These activities assure that the ASW system will remain sufficiently clean such that fouling will not prevent the system from performing its design basis functions. CCW heat exchanger tests on both units will be performed to provide additional confirmation of the adequacy of operational and maintenance practices to assure that the CCW heat exchangers meet their design basis requirements. An equipment control guideline was implemented to ensure compensating actions are taken if the ASW chlorination system becomes inoperable.

I. Plant Conditions

Unit 1 and Unit 2 operated in various modes at various power levels while this condition existed.

II. Description of Event

A. Summary:

On December 30, 1993, at 1150 PST, with Unit 1 in Mode 3 (Hot Standby) at O percent power and Unit 2 in Mode 1 (Power Operation) at 100 percent power, PG&E determined that the auxiliary saltwater (ASW) system (BI) and its associated component cooling water (CCW) heat exchangers (BI)(HX) for both units may not have met their design basis requirements for certain time periods prior to implementation of continuous chlorination. Continuous chlorination was fully implemented in September and November 1992 for Units 1 and 2, respectively. This condition was reported to the NRC as a one-hour, non-emergency report in accordance with 10 CFR 50.72 (b)(1)(ii)(B) at 1150 PST on December 30, 1993.

B. Background:

1. Design

Following a loss of coolant accident (LOCA) or a main steam line break (MSLB) inside containment, the CCW system is required to provide cooling water to the containment fan cooling units (CFCUs) (BK)(FAN) for containment heat removal, and to the various engineered safeguards features (ESF) pump coolers. During the recirculation phase of the LOCA, the CCW system also cools the residual heat removal (RHR) heat exchangers (BP)(HX). In order for the CCW system to perform its function, CCW water temperature must remain at or below 120°F for continuous operation and may exceed 120°F, up to a maximum of 132°F, for no longer than 20 minutes.

The CCW system is also designed to remove heat during normal operation from the CFCUs, ESF pump coolers, and various nonessential heat loads. The CCW system includes three pumps (BI)(P), two heat exchangers, two vital headers and one nonvital header. The heat transferred to the CCW system is transferred to the ASW system through the two heat exchangers. Following an accident, the temperature of the CCW system is primarily a function of heat input to the system from the CFCUs and RHR heat exchangers (during recirculation), and heat removal from the system by the ASW system.

2. Biological Fouling and Scaling

Biological fouling consists of two main components, microfouling and macrofouling.

Macrofouling is the blockage of flow through the heat exchanger tubes due to mussels and barnacles or other foreign materials in the seawater environment. Blocked tubes reduce heat transfer capability by reducing the effective surface area.

Microfouling includes both organic and inorganic materials that adhere to the ASW heat exchanger tubes and, by their presence, degrade heat transfer at the tube surface. Scaling is related to the operation of the cathodic protection system. Calcium carbonate can be expected to plate out on the inside surface near the end of the tubes. Since the calcium carbonate deposit is a thin layer and the affected area is small, the overall impact of calcification on the heat transfer capability is small

C. Event Description:

1. Previous Reportable Events on ASW system

In LER 1-84-040, submitted March 24, 1989, PG&E reported that engineering recommendations for plant operation to assure compliance with the design bases for the CCW system and the ASW system were not incorporated in plant procedures and emergency procedures. Emergency Operating Procedure (EOP) E-O, "Reactor Trip on Safety Injection," was revised to add a new step to verify that both ASW pumps start following a safety injection. If only one pump starts, the operator is instructed to place the second CCW heat exchanger in service.

In LER 1-91-018, submitted January 17, 1992, PG&E determined that the heat load on the CCW system during the cold-leg recirculation phase following a LOCA could potentially exceed the CCW system design basis temperature limits. Because the injection phase had previously been considered the limiting case for CCW temperature, this condition was considered to be outside the design basis of the CCW system. EOP E-1.3, "Transfer to Cold Leg Recirculation," was revised to require reducing CFCU and RHR heat loads if two ASW pumps and two CCW heat exchangers are not operating.

2. Heat Exchanger Reevaluation

In response to GL 89-13, PG&E performed testing of the Units 1 and 2 CCW heat exchangers in February 1991 and September 1991, respectively. Based on engineering judgement at the time, PG&E

concluded that the testing adequately demonstrated that the CCW heat exchangers met design basis requirements.

A QA surveillance report of the ASW system, issued July 28, 1993, identified a concern regarding the ability of the ASW system to satisfy its design basis heat removal requirements with the CCW heat exchanger(s) in the fouled condition corresponding to a differential pressure (dp) of 140 inches of water.

An NRC inspection performed in December 1993 (Inspection Report 50-275/323-93-36) identified a concern with the basis for the operability of the ASW system with regard to CCW heat exchanger macrofouling, microfouling, and tube plugging.

In response to those concerns, PG&E initiated a Technical Review Group (TRG) to perform a comprehensive evaluation of the present and past capability of the ASW system to meet its design basis. The following is a summary of the results of the investigation of the parameters affecting ASW system operability. Detailed results of the investigation are discussed in PG&E Letter No. DCL-94-037 (February 15, 1994).

3. Operability Parameters

   a. Biological Controls on the ASW System

      DCPP has implemented chlorination to control both microand macrofouling. Batch chlorination was in use at DCPP from late-1984 through 1991, although a few periods existed during this timeframe when equipment problems or system enhancement modifications precluded the use of chlorination. Since 1992, the method used has been continuous chlorination. Both methods of chlorination can control the growth of macrofouling as well as microfouling, although continuous chlorination is a superior method. The control of macrofouling requires higher chlorine concentrations than the control of microfouling; however, DCPP maintains sufficient chlorine in the ASW system to control both types of biofouling in the piping and the heat exchangers.

      On August 23, 1990, microfouling samples were taken from CCW 1-2 heat exchanger. Biofouling was noted on the waterbox walls and along the interior surfaces of the individual tubes. This was an unusual circumstance since appreciable microfouling in the four CCW heat exchangers had not been found in previous CCW heat exchanger inspections. CCW 1-1 heat exchanger was inspected September 5, 1990, and no biofouling buildup was noted. In response to the observations noted in CCW 1-2 heat exchanger, daily chlorine injections were made for two weeks following the inspection.

In 1992 continuous chlorination of the ASW system was implemented as follows:

• January 1992	ASW line 1-1
• March 1992	ASW line 2-1
• September 1992	ASW line 1-2
• November 1992	ASW line 2-2

b. Maintenance Practices

Cleaning of heat exchangers during operation is periodically performed to remove debris such as mussels, barnacles, shells, or other debris that is obstructing flow (macrofouling). As discussed below, during operation, differential pressure (dp) is used as a threshold indicator to determine when cleaning is required. In addition, based on an inspection of the heat exchanger during the cleaning activities, waterjetting may also be performed if necessary to remove accumulated biofouling.

In accordance with Maintenance Procedure MP M-56.16, "Heat Exchanger Tube Cleaning,' the heat exchanger tubes are mechanically scraped during each refueling outage (nominally every 18 months: ref. Recurring Task Numbers 51872, 551872, 53587, and 551886). Cleaning of the tubes with a waterjet has been performed periodically in the past during macrofouling cleaning (whenever the dp reaches its administrative limit).

c. CCW Heat Exchanger Differential Pressure

Continuous monitoring of the Up across the heat exchanger is a diagnostic tool and cannot, by itself, quantitatively be used to determine operability. However, it can be used as a threshold indicator to assess the heat exchanger condition during operation. Differential pressure is monitored by taking shift readings of dp, as well as by a dp alarm in the control room. Differential pressure provides an indication of the heat exchanger condition and is used to determine when the heat exchanger should be cleaned. Differential pressure provides an indication of the heat exchanger condition that is qualitatively linked to each heat exchanger's heat transfer capability. Although the measured dp across the heat exchanger does not provide an all-inclusive indicator of heat exchanger performance, it does give a general indication of the combined effect of macrofouling and heavy scaling.

Therefore, the dp measurement, with microfouling under control, is one indicator of overall heat exchanger functionality. Maintenance, surveillance testing, and inspections during cleanings are also other indicators.

Mechanical cleaning of the heat exchangers every outage, and continuous chlorination and periodic waterjetting during operation minimizes microfouling and scaling. Therefore, differential pressure is a reasonable indicator of overall heat exchanger functionality.

The dp setpoint from plant startup until January 1986 was 110 inches, which resulted in a standing alarm. From January 1986 until April 1988, the dp setpoint was 170 inches. From April 1988 until September 1989, the Up setpoint was 167 inches. From September 1989 until November 1989, the setpoint was 120 inches. The current setpoint of 140 inches was initiated in November 1989.

Based on a review of the above macrofouling information, it was determined that the limiting combination of macrofouling and high ocean temperature occurred on November 8, 1987.

d. Operational Controls

As discussed above, PG&E enhanced its emergency procedures in February 1989 to place a second CCW heat exchanger in service if both ASW pumps fail to start following an accident. The emergency procedures were further enhanced in 1991 to include directions regarding equipment configurations to control CCW temperature during recirculation.

4. Heat Exchanger Performance Testing

On February 2, 1991, in response to the requirements of GL 89-13, PG&E performed testing of the Unit 1 CCW heat exchangers to verify their capability to meet design basis (nameplate) heat removal requirements. The performance results were:

COMPONENT	HEAT EXCHANGE RATIO
CCW HX 1-1	1.080
CCW HX 1-2	0.987

On September 1, 1991, PG&E performed testing of the Unit 2 CCW heat exchangers. The performance results were:

COMPONENT	HEAT EXCHANGE RATIO
CCW HX 2-1	1.112
CCW HX 2-2	1.109

Based on consultation with an industry heat exchanger expert and further evaluation of the test results, PG&E now concludes that the CCW 1-2 heat exchanger testing results (which were evaluated using Heat Transfer Consultants, Inc.'s HTC-STX computer model) did not meet the design basis. However, PG&E requested HOLTEC, International to analyze the GL 89-13 test data for the CCW 1-2 heat exchanger. The HOLTEC model was specifically developed for GL 89-13 evaluation and has been widely used by the nuclear power industry. It has been validated using an approved software quality assurance program and has been used in audit responses; therefore, it is considered a good validation of the HTC-STX program. The results of the HOLTEC model reanalysis of the GL 89-13 test data predicted that the CCW 1-2 heat exchanger performance at nameplate condition would be 101 percent with a 95 percent confidence level.

5. Conclusion

On December 30, 1953, at 1150 PST, with Unit 1 in Mode 3 (Hot Standby) at ~ percent power and Unit 2 in Mode 1 (Power Operation) at 100 percent power, POSE determined that the CCW heat exchangers for both tin-its may have not met their design basis prior to implementation of continuous chlorination. This condition was reported to the NRC as a one-hour, non-emergency report in accordance with 10 CFR 50.72 (b)(1)(ii)(B) at 1150 PST on December 30, 1993. Continuous chlorination was fully implemented in September and November 1992 for Units 1 and 2, respectfully.

The continuing investigation reviewed the current maintenance, operational, and testing practices. The maintenance practices that provide assurance that the heat exchangers will remain sufficiently clean of biofouling include continuous chlorination, scraping of the tubes during refueling outages, cleaning of the tubes and tubesheet when the measured dp is 130 inches of water, and declaring the heat exchanger inoperable at 140 inches of water.

The review of historical information determined that a combination of three factors led to the microfouling growth discovered in CCW 1-2 heat exchanger in August 1990. Chlorination was not performed for a period of approximately six months prior to the Unit 1 heat exchanger inspections. During this period, the gaseous chlorine system was out of service for replacement of cast iron piping. Concurrent with the absence of chlorine, the following unusual environmental conditions contributed to the microfouling:

- Beginning in March 1990 and continuing through June, coastal upwelling was experienced. This upwelling increased the nutrient level of the ocean surface waters.

- The high nutrient level, when combined with the rising ambient ocean temperature in July and August, and the absence of chlorine injection, produced ideal conditions for microfouling organisms such as bacteria, diatoms, and filamentous algae.

- CCW 1-2 heat exchanger was the only CCW heat exchanger that was not waterjetted or scraped within seven months prior to conducting the performance test.

In summary, PO&E's review of the operating history of the CCW heat exchangers from plant startup to date resulted in further review of the following periods for potential safety significance:

- Current ASW system condition (after full implementation of continuous chlorination in November 1992).
- System condition between August 1990 and February 1991.
- Operation between August 1986 and March 1988 (operation with a dp setpoint alarm of 170 inches).

D. Inoperable Structures, Components, or Systems that Contributed to the Event:

Chlorination was not performed for a six-month period of time in 1990 due to the replacement of cast iron piping in the chlorination and associated systems.

E. Dates and Approximate Times for Major Occurrences:

1. July 18, 1989:	Generic Letter 89-13 was issued.
2. August 23, 1990:	Samples taken from CCW 1-2 heat exchanger, indicating excessive microfouling.
3. February 1991:	Unit 1 GL 89-13 heat exchanger testing.
4. September 1991:	Unit 2 GL 89-13 heat exchanger testing.
5. November 1992:	Continuous chlorination fully implemented for ASW system.
6. July 28, 1993:	QA surveillance report issued.
7. December 30, 1993:	Event/Discovery date. PG&E determined that CCW 1-2 heat exchanger may have had sufficient microfouling to preclude the CCW system from meeting its design basis on August 23, 1990.

F. Other Systems or Secondary Functions Affected:

None.

G. Method of Discovery:

During a TRG evaluation of an engineering reanalysis, PG&E determined that CCW 1-2 heat exchanger may have had sufficient fouling to have precluded the CCW system from meeting its design basis on August 23, 1990.

H. Operators Actions:

None required.

I. Safety System Responses:

None required.

III. Cause of the Event

A. Immediate Cause:

Fouling.

B. Root Cause:

The root cause of this event is an inadequate understanding of the effects of fouling on the CCW heat exchangers.

C. Contributing Cause:

1. Chlorination frequency.

2. Mechanical cleaning frequency.

IV. Anal YSi S of the Event

The key parameters affecting the performance of the ASH and CCW systems include: macrofouling and microfouling, ASW flow, and ocean temperature. An extensive review of historical maintenance, testing, operational, and biological factors was performed to identify time periods with a high potential for macrofouling and microfouling. During this review of past operation, specific periods of time have been identified during which one or more of these key parameters may have been outside current acceptance criteria. These time periods, and the safety significance of the associated fouling, are discussed below.

Biological Fouling Conditions

The potential for significant microfouling of CCW heat exchanger tubes occurs when certain conditions are met. These conditions include:

- An upwelling of cold, nutrient-rich water from deep ocean layers, which occurs as a result of strong northwesterly winds that characteristically blow during the spring.

- A period of high ocean temperatures, which, following an upwelling period, allows the microorganisms to "bloom." Experience indicates that ocean temperatures of approximately 58°F or greater must be reached over a several week period for the "bloom" to occur.

- The chlorination system is out-of-service for a considerable period prior to and during the "bloom." Without chlorination during the 'bloom" period, microfouling could form on the tubes of the heat exchanger. If chlorination is restarted after the "bloom" has occurred, further microfouling is stopped. However, residual material placed by the microorganisms remains in the tubes as a coating and continues to impact heat exchanger performance. Once deposited, waterjetting or scraping of the tubes is needed to remove the residual material.

Bounding Microfouling Condition

PG&E's evaluation of maintenance and operational practices over Diablo Canyon's operating history indicates that the bounding conditions for potentially significant microfouling only occurred during August 1990. Prior to this period, upwelling of nutrients had occurred and was followed by a period of ocean warming. As a result, a microfouling "bloom" occurred. PO&E's analysis indicates that microfouling reached significant levels in August 1990 as ocean temperature exceeded 58°F. In addition, the chlorination system was out-of-service during this period while PG&E was replacing cast iron piping in the system. When batch chlorination was restored on August 21, 1990, further microfouling ceased. However, the residual material from the microorganisms remained in the CCW heat exchanger tubes until waterjetting or tube scraping was performed. PO&E's review indicates that there were no other time periods when the lack of chlorination and maintenance was coupled with favorable environmental conditions for microfouling.

Of the four CCW heat exchangers, the 1-2 heat exchanger was the most susceptible to microfouling based on its chlorination, maintenance, and operating history. The remaining three heat exchangers received waterjet cleanings between the period of high microfouling potential and the performance of the GL 89-13 performance testing. In addition, two of the other three heat exchangers were operated less frequently during the period of high microfouling potential.

The CCW 1-2 heat exchanger was not waterjetted or scraped during the period from August 1990 until after the performance of the GL 89-13 performance test in February 1991. However, as discussed above, batch chlorination was resumed on August 21, 1990, and PO&E's reanalysis of the February 1991 CCW 1-2 heat exchanger performance test using a certified test model indicates that the CCW 1-2 heat exchanger met its design basis (nameplate) heat removal capacity at that time. PG&E believes that the heat transfer microfouling characteristics of the CCW 1-2 heat exchanger during its associated GL 89-13 testing represent the bounding microfouling case.

PG&E evaluated the highest macrofouling that may have existed coincident with high microfouling. During August 1990, the CCW 1-2 heat exchanger was taken out of service for cleaning. It was not again taken out of service until the test in February 1991, at which time the Up was about 110 inches. The August 1990 dp of about 130 inches represented the highest macrofouling reached during this bounding microfouling period. The level of macrofouling associated with a dp of 130 inches, coupled with an assumed level of microfouling found during the testing of the CCW 1-2 heat exchanger, represents the most limiting fouling of a CCW heat exchanger.

Bounding Macrofouling Condition

PO&E's review of macrofouling data identified periods of operation at an elevated Up (greater than 140 inches). The historical data focused attention on a period from August 1986 to March 1988 during which, on three occasions, the combination of recorded dp and actual ASW temperatures indicated the potential for excessive macrofouling. The apparent bounding case of macrofouling identified in this period occurred on November 8, 1987, when CCW 1-2 heat exchanger was removed from service with a dp of about 170 inches in conjunction with an ocean water daily mean temperature of 59.9° F. A review of environmental conditions associated with this period of high Up determined that coincident conditions required for significant m~crofoul~ng did not exist. PG&E believes that microfouling levels at that time were consistent with the low levels observed during the Unit 2 CCW heat exchanger GL 89-13 tests.

Safety Significance

PG&E has analyzed the bounding cases of heat exchanger fouling for safety significance. These analyses were performed using the mass and energy (M&E) release model that is the licensing basis for DCPP.

The impact of bounding fouling cases on the containment integrity analyses was performed by Westinghouse. Westinghouse evaluated the design basis LOCA, as well as the limiting MSLB accidents for impacts on containment pressure and temperature. The conclusion of these evaluations is that the containment design basis pressure and temperature would not have been exceeded during a postulated LOCA or MSLB.

The design basis CCW temperature limits allow a transient temperature maximum of 132° F for 20 minutes. The temperature limit for continuous

operation is 120° F. PG&E has evaluated the impact of the bounding fouling cases on the limiting post-LOCA CCW temperature transients. Using the current licensing basis M&E release model, PG&E and Westinghouse have determined that the peak CCW temperature would have remained within the design basis CCW temperature limits during the injection phase following a LOCA. The containment conditions calculated by Westinghouse were then used by PG&E to evaluate the CCW temperature transient that would result during the recirculation phase. These evaluations concluded that the CCW temperature could have exceeded its design basis temperature limits in recirculation for an extended period if operator action is not taken.

The potential for the CCW system to overheat during the post-LOCA recirculation phase of an accident was previously identified by PG&E in 1991. LER 1-91-018, "Component Cooling Water System Outside Design Basis," reported that the heat load during cold leg recirculation may exceed the CCW system design basis temperature limits. Specific recirculation transient analyses were not performed. At that time, it was reported that operator action to keep CCW temperatures within design limits was required if the two ASW pump/two CCW heat exchanger configuration could not be established. In response to the LER, guidance to address conditions when both ASW pumps and both CCW heat exchangers were not available was incorporated into step 3.d of EOP E-1.3 in 1991. The potential for elevated CCW temperatures identified in the bounding fouling cases above is due primarily to the heat loads imposed on the system during recirculation, and not specifically caused by the identified heat exchanger fouling. Calculations indicate that, had the 1991 EOP guidance been in place at the time that the bounding conditions existed, the CCW system temperature would have remained within its design basis.

To bound the conditions in place during the 1990 high macro- and microfouling case, as well as the 1987 high macrofouling case, PG&E evaluated the CCW temperature transient assuming the likely operator actions for each period. Prior to the 1991 revision of EOP E-1.3, EOP E-O was revised in 1989 to require placing a second CCW heat exchanger in service when only one ASW pump is available (post-LOCA). Because of the enhanced procedural guidance available to the operators in 1990, the timeline for the period of high microfouling had the operators align the second heat exchanger within 20 minutes following the initiation of the LOCA (This is consistent with operator action described in SSER 16.). A different timeline was used for the period of high macrofouling as this case preceded the 1989 EOP changes. While not formally proceduralized, operator actions believed to be representative of those actions that would have occurred prior to the 1989 EOP changes were used. The timeline would have operators secure two CFCUs 15 minutes after the start of recirculation in response to high CCW temperature alarms and subsequently place the second CCW heat exchanger into service 10 minutes later.

Assuming operator action as described above, the limiting CCW temperature transients were evaluated. The peak CCW temperature for the high macro- and microfouling case was approximately 139°F, and the cumulative time above 120°F was approximately 30 minutes. The peak CCW temperature for the high

macrofouling period was approximately 136°F, and the cumulative time above 120°F was approximately 34 minutes. The impact of the elevated CCW temperatures on the components of the vital CCW headers was evaluated. Westinghouse analyzed the impact of the CCW temperature profile and has determined that the SI and RHR pumps and the CFCU fan motors would perform their design basis function. The CCW pump manufacturer confirmed that the CCW pumps would perform their design basis function at the elevated CCW temperatures. The post-LOCA sampling system may have been temporarily disabled by the elevated CCW temperatures. However, the ability to assess core damage remained available from alternate proceduralized means. The centrifugal charging pumps (CCPs) cannot be shown to continue to be available at these elevated temperatures, although the exact point of failure is not known. However, the CCPs are available for the entire injection phase of the accident. Regardless of the availability of the CCPs for the recirculation phase, Westinghouse and PG&E analyses have determined that during the recirculation phase, other ECCS pumps are available to perform required ECCS functions.

Based on the foregoing detailed analysis of this event, PG&E concludes the following:

- The fouling identified on the CCW heat exchangers would not have resulted in the containment design pressure or temperature being exceeded.
- The CCW design basis temperature limits would only have been exceeded during post-LOCA recirculation.
- All vital components served by the CCW system would have continued to perform their design basis function, or redundant equipment would have been available to perform these functions.

Accordingly, this event had no safety significance and the health and safety of the public would not have been affected.

V. Corrective Actions

A. Immediate Corrective Actions:

1. An operations standing order was prepared to notify the system engineer if the ASW chlorination system becomes inoperable. This will provide assurance that the chlorination system is returned to service quickly enough to prevent excessive CCW heat exchanger microfouling.

2. An operations standing order was prepared to ensure that the CCW heat exchangers are cleaned when the dp reaches 130 inches. In addition, the associated ASW train will be declared inoperable whenever the dp reaches 140 inches. This standing order is applicable for an operating

configuration of one ASW pump running with one CCW HX aligned.

3. STP I-1A, " Routine Shift Checks Required by Licenses," has been revised to require that the CCW heat exchanger dp be verified to be less than 140 inches of water. This revision will incorporate the existing standing order to begin preparations to clean the heat exchangers at 130 inches.

B. Corrective Actions to Prevent Recurrence:

1. The continuous chlorination program for the ASW system has been fully implemented. ASW system continuous chlorination effectively controls the effects of biofouling.

2. In addition to inspections performed when dp limits are reached, a recurring task work order will be initiated to assure that each heat exchanger will be inspected at a frequency of six months and cleaned as required.

3. Additional CCW heat exchanger performance tests on both units will be performed to verify the adequacy of operational and maintenance practices to assure that the CCW heat exchangers meet design basis requirements. The tests will be conducted during the 1R6 and 2R6 refueling outages and will include dp measurement. Upon completion of additional heat exchanger performance tests scheduled for 1R6 and 2R6, PG&E will reevaluate the dp setpoint.

4. Enhanced ASW flow instrumentation will be installed with local readouts.

5. ECG 17.2 has been approved to provide administrative controls on the ASW chlorination system. This ECG will document compensating actions to be taken if the ASW chlorination system is inoperable for greater than 14 days.

6. PG&E agrees that trending of the dp increase on each CCW heat exchanger would be useful in anticipating calcification and other buildup that may affect dp. Consequently, PG&E will revise STP M-26 to require a formal trending program to monitor this parameter.

7. An Integrated Problem Response Team (IPRT) will be conducted on the ASW, CCW, and interfacing systems by the end of 1994. This IPRT will thoroughly and critically review these systems. Membership of the IPRT will include operations, quality services, maintenance, Westinghouse, and engineering personnel. Based on the results of the IPRT, DCM S-17B will

be revised to provide additional information on ASW system heat removal capacity.

VI. Additional Information

A. Failed Components:

None.

B. Previous LERs on Similar Problems:

1. LER 1-91-018-01, "Component Cooling Water System Outside Design Basis Due to Personnel Error." PG&E determined that the heat load on the CCW system during the cold-leg recirculation phase following a LOCA could potentially exceed the CCW system design basis temperature limits. Because the injection phase had previously been considered the limiting case for CCW temperature, this condition was considered to be outside the design basis of the CCW system. The root cause was attributed to personnel error. The corrective actions to prevent recurrence included additional training for design engineers to emphasize that data known to be conservative for one application may be nonconservative for another application. Because this event did not address the potential for biofouling of heat exchangers, the corrective actions taken would not have prevented the current event.

2. LER 1-84-040, "CCW and ASW System Design Basis Requirements Not Incorporated into Plant Procedures Due to Inadequate Tracking of Resolution from Correspondence and Communication."

   Engineering recommendations for plant operation to assure compliance with the design basis for the CCW and ASW systems were not incorporated in plant procedures. Since this event involved incorporation of design constraints in plant procedures, corrective actions taken to prevent recurrence could not have prevented the current event since they would not affect biofouling in the CCW heat exchangers.

Pacific Gas and Electric Company

77 Beale Street, Room 1451-B14A
San Francisco, CA 94105
Mailing Address
Mail Code B14A
P.O. Box 770000
San Francisco, CA 94177
Fax 415/973-2313

Gregory M. Rueger
Senior Vice President and
General Manager
Nuclear Power Generation

May 27, 1994

PG&E Letter DCL 94-120

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

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Licensee Event Report 1-93-012-02
Auxiliary Saltwater System Outside Design Basis Due to Fouling

Gentlemen:

Pursuant to 10 CFR 50.73(a)(2)(ii)(B), PG&E is submitting the enclosed revision to Licensee Event Report 1-93-012 concerning the auxiliary saltwater (ASW) system being outside its design basis due to fouling. This revision is being submitted to report the results of additional testing performed on the component cooling water (CCW) heat exchangers during the Unit 1 sixth refueling outage.

PG&E's comprehensive evaluation concluded that this event had no safety significance and that the health and safety of the public were not affected.

Sincerely,

Gregory M. Rueger

cc: L. J. Callan
Mary H. Miller
Kenneth E. Perkins
Sheri R. Peterson
Diablo Distribution
INPO

DCO-93-EN-N022

Enclosure

6475S/DPS/2246

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Diablo Canyon Unit 1	0 5 0 0 0 2 7 5	1 OF 16

TITLE (4) AUXILIARY SALTWATER SYSTEM OUTSIDE DESIGN BASIS DUE TO FOULING

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MON	DAY	YR	YR	SEQUENTIAL NUMBER	REVISION NUMBER	MON	DAY	YR	FACILITY NAMES	DOCKET NUMBER (S)
12	30	93	93	- 0 1 2 -	0 2	05	27	94	Diablo Canyon Unit 2	0 5 0 0 0 3 2 3
										0 5 0 0 0

OPERATING MODE (9): 3

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11)

x 10 CFR 50.73(a)(2)(iv)

OTHER -

(Specify in Abstract below and in text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

	TELEPHONE NUMBER	
	AREA CODE	
DAVID P. SISK - SENIOR REGULATORY COMPLIANCE ENGINEER	805	545-4420

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
[ ] YES (If yes, complete EXPECTED SUBMISSION DATE)	[x] NO				

ABSTRACT (16)

On December 30, 1993, at 1150 PST, with Unit 1 in Mode 3 (Hot Standby) at 0 percent power and Unit 2 in Mode 1 (Power Operation) at 100 percent power, PG&E determined that the auxiliary saltwater (ASW) system and its associated component cooling water (CCW) heat exchangers for both units may not have met their design basis for certain time periods prior to implementation of continuous chlorination. Continuous chlorination was fully implemented in September and November 1992 for Units 1 and 2, respectively. This condition was reported to the NRC as a one-hour, non-emergency report in accordance with 10 CFR 50.72 (b)(1)(ii)(B) at 1150 PST on December 30, 1993.

The cause of this condition was an inadequate understanding of the effects of fouling on the CCW heat exchangers.

The ASW systems for both units currently are operable given the present maintenance, operational, and testing activities. These activities assure that the ASW system will remain sufficiently clean such that fouling will not prevent the system from performing its design basis functions. CCW heat exchanger tests on both units will be performed to provide additional confirmation of the adequacy of operational and maintenance practices to assure that the CCW heat exchangers meet their design basis requirements. An equipment control guideline was implemented to ensure compensating actions are taken if the ASW chlorination system becomes inoperable.

6475S

I. Plant Conditions

Unit 1 and Unit 2 operated in various modes at various power levels while this condition existed.

II. Description of Event

A. Summary:

On December 30, 1993. at 1150 PST, with Unit 1 in Mode 3 (Hot Standbys) at 0 percent power and Unit 2 in Mode 1 (Power Operation) at 100 percent power, POSE determined that the auxiliary saltwater (ASW) system (Pi) and its associated component cooling water (CCW) heat exchangers (BI)(HX) for both units may not have met their design basis requirements for certain time periods prior to implementation of continuous chlorination. Continuous chlorination was fully implemented in September and November 1992 for Units 1 and 2, respectively. This condition was reported to the NRC as a one-hour, non-emergency report in accordance with 10 CFR 50.72 (b)(1)(ii)(B) at 1150 PST on December 30, 1993.

B. Background:

1. Design

Following a loss of coolant accident (LOCA) or a main steam line break (MSLB) inside containment, the CCW system is required to provide cooling water to the containment fan cooling units (CFCUs) (BK)(FAN) for containment heat removal, and to the various engineered safeguards features (ESF) pump coolers. During the recirculation phase of the LOCA, the CCW system also cools the residual heat removal (RHR) heat exchangers (BP)(HX). In order for the CCW system to perform its function, CCW water temperature must remain at or below 120°F for continuous operation and may exceed 120°F, up to a maximum of 132°F, for no longer than 20 minutes.

The CCW system is also designed to remove heat during normal operation from the CFCUs, ESF pump coolers, and various nonessential heat loads. The CCW system includes three pumps (BI)(P), two heat exchangers, two vital headers and one non-vital header. The heat transferred to the CCW system is transferred to the ASW system through the two heat exchangers. Following an accident, the temperature of the CCW system is primarily a function of heat input to the system from the CFCUs and RHR heat exchangers (during recirculation), and heat removal from the system by the ASW system.

TEXT (17)

6475S

2. Biological Fouling and Scaling

Biological fouling consists of two main components, microfouling and macrofouling.

Macrofouling is the blockage of flow through the heat exchanger tubes due to mussels and barnacles or other foreign materials in the seawater environment. Blocked tubes reduce heat transfer capability by reducing the effective surface area.

Microfouling includes both organic and inorganic materials that adhere to the ASW heat exchanger tubes and, by their presence, degrade heat transfer at the tube surface. Scaling is related to the operation of the cathodic protection system. Calcium carbonate can be expected to plate out on the inside surface near the end of the tubes. Since the calcium carbonate deposit is a thin layer and the affected area is small, the overall impact of calcification on the heat transfer capability is small.

C. Event Description:

1. Previous Reportable Events on ASW system

In LER 1-84-040, submitted March 24, 1989, PG&E reported that engineering recommendations for plant operation to assure compliance with the design bases for the CCW system and the ASW system were not incorporated in plant procedures and emergency procedures. Emergency Operating Procedure (EOP) E-O, "Reactor Trip on Safety Injection," was revised to add a new step to verify that both ASW pumps start following a safety injection. If only one pump starts, the operator is instructed to place the second CCW heat exchanger in service.

In LER 1-91-018, submitted January 17, 1992, PG&E determined that the heat load on the CCW system during the cold-leg recirculation phase following a LOCA could potentially exceed the CCW system design basis temperature limits. Because the injection phase had previously been considered the limiting case for CCW temperature, this condition was considered to be outside the design basis of the CCW system. EOP E-1.3, "Transfer to Cold Leg Recirculation," was revised to require reducing CFCU and RHR heat loads if two ASW pumps and two CCW heat exchangers are not operating.

2. Heat Exchanger Reevaluation

In response to GL 89-13, PG&E performed testing of the Units 1 and 2 CCW heat exchangers in February 1991 and September 1991, respectively. Based on engineering judgment at the time, PG&E concluded that the testing adequately demonstrated that the CCW heat exchangers met design basis requirements.

A QA surveillance report of the ASW system, issued July 28, 1993, identified a concern regarding the ability Of the has system to satisfy its design basis heat removal requirements with the CCW heat exchanger(s) in the fouled condition corresponding to a differential pressure (dp) of 140 inches of water.

An NRC inspection performed in December 1993 (Inspection Report 50-275/323-93-36) identified a concern with the basis for the operability of the ASW system with regard to CCW heat exchanger macrofouling, microfouling, and tube plugging.

In response to those concerns, PG&E initiated a Technical Review Group (TRG) to perform a comprehensive evaluation of the present and past capability of the ASW system to meet its design basis. The following is a summary of the results of the investigation of the parameters affecting ASW system operability. Detailed results of the investigation are discussed in PG&E Letter No. DCL-94-037 (February 15, 1994).

3. Operability Parameters

a. Biological Controls on the ASW System

DCPP has implemented chlorination to control both micro and macrofouling. Batch chlorination was In use at DCPP from late-1984 through 1991, although a few periods existed during this timeframe when equipment problems or system enhancement modifications precluded the use of chlorination. Since 1992, the method used has been continuous chlorination. Both methods of chlorination can control the growth of macrofouling as well as microfouling, although continuous chlorination is a superior method. The control of macrofouling requires higher chlorine concentrations than the control of microfouling; however, DCPP maintains sufficient chlorine in the ASW system to control both types of biofouling in the piping and the heat exchangers.

On August 23, 1990, microfouling samples were taken from CCW 1-2 heat exchanger. Biofouling was noted on the waterbox walls and along the interior surfaces of the individual tubes. This was an unusual circumstance since appreciable microfouling in the four CCW heat exchangers had not been found in previous CCW heat exchanger inspections. CCW 1-1 heat exchanger was inspected September 5, 1990, and no biofouling buildup was noted. In response to the observations noted in CCW 1-2 heat exchanger, daily chlorine injections were made for two weeks following the inspection.

In 1992 continuous chlorination of the ASW system was implemented as follows:

- January 1992 ASW line 1-1
- March 1992 ASW line 2-1
- September 1992 ASW line 1-2
- November 1992 ASW line 2-2

b. Maintenance Practices

Cleaning of heat exchangers during operation is periodically performed to remove debris such as mussels, barnacles, shells, or other debris that is obstructing flow (macrofouling). As discussed below, during operation, differential pressure (dp) is used as a threshold indicator to determine when cleaning is required. In addition, based on an inspection of the heat exchanger during the cleaning activities, waterjetting may also be performed if necessary to remove accumulated biofouling.

In accordance with Maintenance Procedure MP M-56.16, "Heat Exchanger Tube Cleaning," the heat exchanger tubes are mechanically scraped during each refueling outage (nominally every 18 months: ref. Recurring Task Numbers 51872, 551872, 53587, and 551886). Cleaning of the tubes with a waterjet has been performed periodically in the past during macrofouling cleaning (whenever the dp reaches its administrative limit).

C. CCW Heat Exchanger Differential Pressure

Continuous monitoring of the dp across the heat exchanger is a diagnostic tool and cannot, by itself, quantitatively be used to determine operability. However, it can be used as a threshold indicator to assess the heat exchanger

condition during operation. Differential pressure is monitored by taking shift readings of dp, as well as by a Up alarm in the control room. Differential pressure provides an indication of the heat exchanger condition and is used to determine when the heat exchanger should be cleaned. Differential pressure provides an indication of the heat exchanger condition that is qualitatively linked to each heat exchanger's heat transfer capability. Although the measured Up across the heat exchanger does not provide an all-inclusive indicator of heat exchanger performance, it does give a general indication of the combined effect of macrofouling and heavy scaling. Therefore, the Up measurement, with microfouling under control, is one indicator of overall heat exchanger functionality. Maintenance, surveillance testing, and inspections during cleanings are also other indicators.

Mechanical cleaning of the heat exchangers every outage, and continuous chlorination and periodic waterjetting during operation minimizes microfouling and scaling. Therefore, differential pressure is a reasonable indicator of overall heat exchanger functionality.

The dp setpoint from plant startup until January 1986 was 110 inches, which resulted in a standing alarm. From January 1986 until April 1988, the dp setpoint was 170 inches. From April 1988 until September 1989, the dp setpoint was 167 inches. From September 1989 until November 1989, the setpoint was 120 inches. The current setpoint of 140 inches was initiated in November 1989.

Based on a review of the above macrofouling information, it was determined that the limiting combination of macrofouling and high ocean temperature occurred on November 8, 1987.

d. Operational Controls

As discussed above, PG&E enhanced its emergency procedures in February 1989 to place a second COW heat exchanger in service if both ASW pumps fail to start following an accident. The emergency procedures were further enhanced in 1991 to include directions regarding equipment configurations to control COW temperature during recirculation.

4. Heat Exchanger Performance Testing

On February 2, 1991, in response to the requirements of GL 89-13, PG&E performed testing of the Unit 1 CCW heat exchangers to verify their capability to meet design basis (nameplate) heat removal requirements. The performance results were:

COMPONENT	HEAT EXCHANGE RATIO
CCW HX 1-1	1.080
CCW HX 1-2	0.987

On September 1, 1991, PG&E performed testing of the Unit 2 CCW heat exchangers. The performance results were:

COMPONENT	HEAT EXCHANGE RATIO
CCW HX 2-1	1.112
CCW HX 2-2	1.109

Based on consultation with an industry heat exchanger expert and further evaluation of the test results, PG&E now concludes that the CCW 1-2 heat exchanger testing results (which were evaluated using Heat Transfer Consultants, Inc.'s HTC-STX computer model) did not meet the design basis. However, PG&E requested HOLTEC, International to analyze the GL 89-13 test data for the CCW 1-2 heat exchanger. The HOLTEC model was specifically developed for GL 89-13 evaluation and has been widely used by the nuclear power industry. It has been validated using an approved software quality assurance program and has been used in audit responses; therefore, it is considered a good validation of the HTC-STX program. The results of the HOLTEC model reanalysis of the GL 89-13 test data predicted that the CCW 1-2 heat exchanger performance at nameplate condition would be 101 percent with a 95 percent confidence level.

Additional testing on the Unit 1 CCW heat exchanger was completed on April 26, 1994. These tests indicate that the heat exchangers have significant margin above design basis and that both Unit 1 heat exchangers are performing significantly better than the 1991 GL 89-13 test results described above. The results of the tests are as follows:

COMPONENT	HEAT EXCHANGER RATIO
CCW HX 1-1	1.176
CCW HX 1-2	1.160

5. Conclusion

On December 30, 1993, at 1150 PST, with Unit 1 in Mode 3 (Hot Standby) at O percent power and Unit 2 in Mode 1 (Power Operation) at

100 percent power, PG&E determined that the CCW heat exchangers for both units may have not met their design basis prior to implementation of continuous chlorination. This condition was reported to the NRC as a one-hour, non-emergency report in accordance with 10 CFR 50.72 (b)(1)(ii)(B) at 1150 PST on December 30, 1993. Continuous chlorination was fully implemented in September and November 1992 for Units 1 and 2, respectfully.

The continuing investigation reviewed the current maintenance, operational, and testing practices. The maintenance practices that provide assurance that the heat exchangers will certain sufficiently clean of biofouling include continuous chlorination, scraping of the tubes Goring refueling outages, cleaning of the tubes and tubesheet when the measured Up is 130 inches of water, and declaring the heat exchanger inoperable at 140 inches of water.

The review of historical information determined that a combination of three factors led to the microfouling growth discovered in CCW 1-2 heal exchanger in August 1990. Chlorination was not performed for a period of approximately six months prior to the Unit 1 heat exchanger inspections. During this period, the gaseous chlorine system was out of service for replacement of cast iron piping. Concurrent with the absence of chlorine, the following unusual environmental conditions contributed to the microfouling:

- Beginning in March 1990 and continuing through June, coastal upwelling was experienced. This upwelling increased the nutrient level of the ocean surface waters.

- The high nutrient level, when combined with the rising ambient ocean temperature in July and August, and the absence of chlorine injection, produced ideal conditions for microfouling organisms such as bacteria, diatoms, and filamentous algae.

- CCW 1-2 heat exchanger was the only CCW heat exchanger that was not waterjetted or scraped within seven months prior to conducting the performance test.

In summary, PG&E's review of the operating history of the CCW heat exchangers from plant startup to date resulted in further review of the following periods for potential safety significance:

- Current ASW system condition (after full implementation of continuous chlorination in November 1992).

- System condition between August 1990 and February 1991.

- Operation between August 1986 and March 1988 (operation with a Up setpoint alarm of 170 inches).

D. Inoperable Structures, Components, or Systems that Contributed to the Event:

Chlorination was not performed for a six-month period of time in 1990 due to the replacement of cast iron piping in the chlorination and associated systems.

E. Dates and Approximate Times for Major Occurrences:

1.	July IS, 1989:	Generic Letter 89-13 was issued.
2.	August 23, 1990:	Samples taken from CCW 1-2 heat exchanger, indicating excessive microfouling.
3.	February 1991:	Unit 1 GL 89-13 heat exchanger testing.
4.	September 1991:	Unit 2 GL 89-13 heat exchanger testing.
5.	November 1992:	Continuous chlorination fully implemented for ASW system.
6.	July 28, 1993:	QA surveillance report issued.
7.	December 30, 1993:	Event/Discovery date. PG&E determined that CCW 1-2 heat exchanger may have had sufficient microfouling to preclude the CCW system from meeting its design basis on August 23, 1990.

F. Other Systems or Secondary Functions Affected:

None.

G. Method of Discovery:

During a TRG evaluation of an engineering reanalysis, PG&E determined that CCW 1-2 heat exchanger may have had sufficient fouling to have precluded the CCW system from meeting its design basis on August 23, 1990.

H. Operators Actions:

None required.

I. Safety System Responses:

None required.

III. Cause of the Event

A. Immediate Cause:

Fouling

B. Root Cause:

The loot cause of this event is an inadequate understanding of the effects of fouling on the CCW heat exchangers.

C. Contributing Cause.

1. Chlorination frequency.

2. Mechanical cleaning frequency.

IV. Analysis of the Event

The key parameters affecting the performance of the ASW and CCW systems include: macrofouling and microfouling, ASW flow, and ocean temperature. An extensive review of historical maintenance, testing, operational, and biological factors was performed to identify time periods with a high potential for macrofouling and microfouling. During this review of past operation, specific periods of time have been identified during which one or more of these key parameters may have been outside current acceptance criteria. These time periods, and the safety significance of the associated fouling, are discussed below.

Biological Fouling Conditions

The potential for significant microfouling of CCW heat exchanger tubes occurs when certain conditions are met. These conditions include:

- An upwelling of cold, nutrient-rich water from deep ocean layers, which occurs as a result of strong northwesterly winds that characteristically blow during the spring.

- A period of high ocean temperatures, which, following an upwelling period, allows the microorganisms to abloom." Experience indicates that ocean temperatures of

approximately 58°F or greater must be reached over a several week period for the "bloom" to occur.

- The chlorination system is out-of-service for a considerable period prior to and during the "bloom." Without chlorination during the "bloom" period, microfouling could form on the tubes of the heat exchanger. If chlorination is restarted after the "bloom" has occurred, further microfouling is stopped. However, residual material placed by the microorganisms remains in the tubes as a coating and continues to impact heat exchanger performance. Once deposited, waterjetting or scraping of the tubes is needed to remove the residual material.

Bounding Microfouling Condition

PG&E's evaluation of maintenance and operational practices over Diablo Canyon's operating history indicates that the bounding conditions for potentially significant microfouling only occurred during August 1990. Prior to this period, upwelling of nutrients had occurred and was followed by a period of ocean warming. As a result, a microfouling "bloom" occurred. PG&E's analysis indicates that microfouling reached significant levels in August 1990 as ocean temperature exceeded 58°F. In addition, the chlorination system was out-of-service during this period while PG&E was replacing cast iron piping in the system. When batch chlorination was restored on August 21, 1990, further microfouling ceased. However, the residual material from the microorganisms remained in the CCW heat exchanger tubes until waterjetting or tube scraping was performed. PG&E's review indicates that there were no other time periods when the lack of chlorination and maintenance was coupled with favorable environmental conditions for microfouling.

Of the four CCW heat exchangers, the 1-2 heat exchanger was the most susceptible to microfouling based on its chlorination, maintenance, and operating history. The remaining three heat exchangers received waterjet cleanings between the period of high microfouling potential and the performance of the GL 89-13 performance testing. In addition, two of the other three heat exchangers were operated less frequently during the period of high microfouling potential.

The CCW 1-2 heat exchanger was not waterjetted or scraped during the period from August 1990 until after the performance of the GL 89-13 performance test in February 1991. However, as discussed above, batch chlorination was resumed on August 21, 1990, and PG&E's reanalysis of the February 1991 CCW 1-2 heat exchanger performance test using a certified test model indicates that the CCW 1-2 heat exchanger met its design basis (nameplate) heat removal capacity at that time. PG&E believes that the heat transfer microfouling characteristics of the CCW 1-2 heat

exchanger during its associated GL 89-13 testing represent the bounding microfouling case.

PG&E evaluated the highest macrofouling that may have existed coincident with high microfouling. During August 1990, the CCW 1-2 heat exchanger was taken out of service for cleaning. It was not again taken out of service until the test in February 1991, at which time the Up was about 110 inches. The August 1990 Up of about 130 inches represented the highest macrofouling reached during this bounding microfouling period. The level of macrofouling associated with a dp of 130 inches, coupled with an assumed level of microfouling found during the testing of the CCW 1-2 heat exchanger, represents the most limiting fouling of a CCW heat exchanger.

Bounding Macrofouling Condition

PGE's review of macrofouling data identified periods of operation at an elevated dp (greater than 140 inches). The historical data focused attention on a period from August 1986 to March 1988 during which, on three occasions, the combination of recorded dp and actual ASW temperatures indicated the potential for excessive macrofouling. The apparent bounding case of macrofouling identified in this period occurred on November 8, 1987, when CCW 1-2 heat exchanger was removed from service with a Up of about 170 inches in conjunction with an ocean water daily mean temperature of 59.9° F. A review of environmental conditions associated with this period of high Up determined that coincident conditions required for significant microfouling did not exist. PG&E believes that microfouling levels at that time were consistent with the low levels observed during the Unit 2 CCW heat exchanger GL 89-13 tests.

Safety Significance

PG&E has analyzed the bounding cases of heat exchanger fouling for safety significance. These analyses were performed using the mass and energy (M&E) release model that is the licensing basis for DCPP.

The impact of bounding fouling cases on the containment integrity analyses was performed by Westinghouse. Westinghouse evaluated the design basis LOCA, as well as the limiting MSLB accidents for impacts on containment pressure and temperature. The conclusion of these evaluations is that the containment design basis pressure and temperature would not have been exceeded during a postulated LOCA or MSLB.

The design basis CCW temperature limits allow a transient temperature maximum of 132° F for 20 minutes. The temperature limit for continuous operation is 120° F. PG&E has evaluated the impact of the bounding fouling cases on the limiting post-LOCA CCW temperature transients. Using the current licensing basis M&E release model, PG&E and Westinghouse have determined that the peak CCW temperature would have remained within the design basis CCW temperature limits during the injection phase following a LOCA. The containment conditions calculated by

Westinghouse were then used by PG&E to evaluate the CCW temperature transient that would result during

the recirculation phase. These evaluations concluded that the CCW temperature could have exceeded its design basis temperature limits in recirculation for an extended period if operator action is not taken.

The potential for the CCW system to overheat during the post-LOCA recirculation phase of an accident was previously identified by PG&E in 1991. LER l-91-018, "Component Cooling Water System Outside Design Basis,' reported that the heat load during cold leg recirculation may exceed the CCW system design basis temperature limits. Specific recirculation transient analyses were not performed. At that time, it was reported that operator action to keep CCW temperatures within design limits was required if the two ASW pump/two CCW heat exchanger configuration could not be established. In response to the LER, guidance to address conditions when both ASW pumps and both CCW heat exchangers were not available was incorporated into step 3.d of EOP E-1.3 in 1991. The potential for elevated CCW temperatures identified in the bounding fouling cases above is due primarily to the heat loads imposed on the system during recirculation, and not specifically caused by the identified heat exchanger fouling. Calculations indicate that, had the 1991 EOP guidance been in place at the time that the bounding conditions existed, the CCW system temperature would have remained within its design basis.

To bound the conditions in place during the 1990 high macro- and microfouling case, as well as the 1987 high macrofouling case, PG&E evaluated the CCW temperature transient assuming the likely operator actions for each period. Prior to the 1991 revision of EOP E-1.3, EOP E-O was revised in 1989 to require placing a second CCW heat exchanger in service when only one ASW pump is available (post-LOCA). Because of the enhanced procedural guidance available to the operators in 1990, the timeline for the period of high microfouling had the operators align the second heat exchanger within 20 minutes following the initiation of the LOCA (This is consistent with operator action described in SSER 16.). A different timeline was used for the period of high macrofouling as this case preceded the 1989 EOP changes. While not formally proceduralized, operator actions believed to be representative of those actions that would have occurred prior to the 1989 EOP changes were used. The timeline would have operators secure two CFCUs 15 minutes after the start of recirculation in response to high CCW temperature alarms and subsequently place the second CCW heat exchanger into service 10 minutes later.

Assuming operator action as described above, the limiting CCW temperature transients were evaluated. The peak CCW temperature for the high macro- and microfouling case was approximately 139°F, and the cumulative time above 120°F was approximately 30 minutes. The peak CCW temperature for the high macrofouling period was approximately 136°F, and the cumulative time above 120°F was approximately 34 minutes. The impact of the elevated CCW temperatures on the components of the vital CCW headers was evaluated. Westinghouse analyzed the impact of the CCW temperature profile and has

determined that the SI and RHR pumps and the CFCU fan motors would perform their design basis function. The CCW pump manufacturer confirmed that the CCW pumps would perform their design basis function at the elevated CCW temperatures. The post-LOCA sampling system may have been temporarily disabled by the elevated CCW temperatures. However, the ability to assess core damage remained available from alternate proceduralized means. The centrifugal charging pumps (CCPs) cannot be shown to continue to be available at these elevated temperatures, although the exact point of failure is not known. However, the CCPs are available for the entire injection phase of the accident. Regardless of the availability of the CCPs for the recirculation phase, Westinghouse and POSE analyses have determined that during the recirculation phase, other ECCS pumps are available to perform required ECCS functions.

Based on the foregoing detailed analysis of this event, PG&E concludes the following:

- The fouling identified on the CCW heat exchangers would not have resulted in the containment design pressure or temperature being exceeded.
- The CCW design basis temperature limits would only have been exceeded during post-LOCA recirculation.
- All vital components served by the CCW system would have continued to perform their design basis function, or redundant equipment would have been available to perform these functions.

Accordingly, this event had no safety significance and the health and safety of the public would not have been affected.

V. Corrective Actions

A. Immediate Corrective Actions:

1. An operations standing order was prepared to notify the system engineer if the ASW chlorination system becomes inoperable. This will provide assurance that the chlorination system is returned to service quickly enough to prevent excessive CCW heat exchanger microfouling.

2. An operations standing order was prepared to ensure that the CCW heat exchangers are cleaned when the dp reaches 130 inches. In addition, the associated ASW train will be declared inoperable whenever the dp reaches 140 inches. This standing order is applicable for an operating configuration of one ASW pump running with one CCW HX aligned.

3. STP I-1A, " Routine Shift Checks Required by Licenses," has been revised to require that the CCW heat exchanger dp be verified to be less than 140 inches of water. This revision will incorporate the existing standing order to begin preparations to clean the heat exchangers at 130 inches.

B. Corrective Actions to Prevent Recurrence:

1. The continuous chlorination program for the ASW system has been fully implemented. ASW system continuous chlorination effectively controls the effects of biofouling.

2. In addition to inspections performed when Up limits are reached, a recurring task work order will be initiated to assure that each heat exchanger will be inspected at a frequency of six months and cleaned as required.

3. Additional CCW heat exchanger performance tests on both units will be performed to verify the adequacy of operational and maintenance practices to assure that the CCW heat exchangers meet design basis requirements. The tests will be conducted during the 1R6 and 2R6 refueling outages and will include dp measurement. Upon completion of additional heat exchanger performance tests scheduled for 1R6 and 2R6, PG&E will reevaluate the Up setpoint.

4. Enhanced ASW flow instrumentation will be installed with local readouts.

5. ECG 17.2 has been approved to provide administrative controls on the ASW chlorination system. This ECG will document compensating actions to be taken if the ASW chlorination system is inoperable for greater than 14 days.

6. PG&E agrees that trending of the dp increase on each CCW heat exchanger would be useful in anticipating calcification and other buildup that may affect dp. Consequently, PG&E will revise STP M-26 to require a formal trending program to monitor this parameter.

7. An Integrated Problem Response Team (IPRT) will be conducted on the ASW, CCW, and interfacing systems by the end of 1994. This IPRT will thoroughly and critically review these systems. Membership of the IPRT will include operations, quality services, maintenance, Westinghouse, and engineering personnel. Based on the results of the IPRT, DCM S-17B will

be revised to provide additional information on ASW system heat removal capacity.

VI. Additional Information

A. Failed Components:

None.

B. Previous LERs on Similar Problems:

1. LER 1-91-018-01, "Component Cooling Water System Outside Design Basis Due to Personnel Error."

   PG&E determined that the heat load on the CCW system during the cold-leg recirculation phase following a LOCA could potentially exceed the CCW system design basis temperature limits. Because the injection phase had previously been considered the limiting case for CCW temperature, this condition was considered to be outside the design basis of the CCW system. The root cause was attributed to personnel error. The corrective actions to prevent recurrence included additional training for design engineers to emphasize that data known to be conservative for one application may be nonconservative for another application. Because this event did not address the potential for biofouling of heat exchangers, the corrective actions taken would not have prevented the current event.

2. LER 1-84-040, "CCW and ASW System Design Basis Requirements Not Incorporated into Plant Procedures Due to Inadequate Tracking of Resolution from Correspondence and Communication."

   Engineering recommendations for plant operation to assure compliance with the design basis for the CCW and ASW systems were not incorporated in plant procedures. Since this event involved incorporation of design constraints in plant procedures, corrective actions taken to prevent recurrence could not have prevented the current event since they would not affect biofouling in the CCW heat exchangers.

Pacific Gas and Electric Company

77 Beale Street, Room 1451-B14A
P.O. Box 770000
San Francisco, CA 94177
415/973-4684
Fax 415/973-2313

Gregory M. Rueger
Senior Vice President and
General Manager
Nuclear Power Generation

August 5, 1994

PG&E Letter DCL-94-174

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

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Reply to Notice of Violation in NRC Enforcement Action 94-056
(NRC Inspection Report Nos. 50-275/94-08 and 50-323/94-08)

Gentlemen:

NRC Enforcement Action 94-056, dated July 14, 1994, contained a Notice of Violation that cited one Severity Level III violation. The violation involved the failure of PG&E's engineering staff to promptly identify and correct issues that arose as a result of tests performed in 1991 to determine whether the Component Cooling Water Heat Exchanger 1-2 had the ability to remove the design basis heat load. The root cause of the violation was determined to be inadequate attention to engineering practices that should have ensured clear definition of test acceptance criteria for the heat exchanger testing prior to the test being performed and a failure to comprehensively resolve the negative test results in a timely manner. Specific concern was expressed about PG&E's failure to take advantage of several opportunities, particularly our own Quality Assurance organization's self-identification of the deficiency in mid-1993, to thoroughly resolve the issue prior to the NRC's inspection in late 1993.

As discussed in DCL-94-037, dated February 15, 1994, and DCL-94-049, dated March 8, 1994, PG&E conducted a comprehensive evaluation of these concerns and has taken extensive corrective actions to address them. The commitments made in these previous responses constitute the corrective actions we have taken or intend to take. PG&E believes that its previous Generic Letter (GL) 89-13 program, combined with these additional corrective actions, provide assurance that the ASW system is fully operable and capable of meeting its design basis. Recent testing and inspection activities confirm the effectiveness of these actions.

PG&E agrees with the violation. PG&E's response to the Notice of Violation is enclosed.

Sincerely,

Gregory M. Rueger

Subscribed and sworn to before me
this 5th day of August 1994

Attorneys for Pacific Gas and
Electric Company
Howard V. Golub
Christopher J. Warner

Notary Public

Christopher J. Warner

cc: L. J. Callan
Mary H. Miller
Kenneth E. Perkins
Sheri R. Peterson
Diablo Distribution

Enclosure

DC0-94-EN-N022

6552S/TLG/2246

ENCLOSURE

REPLY TO NOTICE OF VIOLATION IN NRC ENFORCEMENT ACTION 94-056

On July 14, 1994, as part of NRC Inspection Report Nos. 50-275/94-08 and 50-23/94-08, NRC Region IV issued Enforcement Action 94-056 that contained a Notice of Violation citing one Severity Level III violation for Diablo Canyon Power Plant Unit 1. The statement of violation and PG&E's response follow.

STATEMENT OF VIOLATION

"During an NRC inspection conducted on February 28, March 1, and March 8, 1994, a violation of NRC requirements was identified. In accordance with the 'General Statement of Policy and Procedure for NRC Enforcement Actions,' 10 CFR Part 2, Appendix C, the particular violation is set forth below:

> 10 CFR Part 50, Appendix B, Criterion XVI, 'Corrective Action,' states, in part, that measures shall be established to assure that conditions adverse to quality, such as failures and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.
>
> Contrary to the above, during a test conducted on February 2, 1991, Component Cooling Water (CCW) Heat Exchanger 1-2 failed to demonstrate the ability to remove the design basis heat load, as documented in Field Test Report 420DC-91.1156, and the measures established by the licensee did not assure that this significant condition adverse to quality was promptly corrected or that the cause of the condition was determined. Despite this condition being recognized in the above referenced Field Test Report dated November 22, 1991, in Action Request No. A0306715 dated May 10, 1993, and in Quality Assurance report SQA-93-0031 dated July 28, 1993, the licensee did not take prompt action to correct this condition, to assess the impact of fouling on heat exchanger performance or to determine the significance of this condition with respect to the operability of the Auxiliary Saltwater System (ASW).

This is a Severity Level III violation (Supplement I)."

REASON FOR THE VIOLATION

PG&E agrees that resolution of the original 1991 heat exchanger testing issues and the 1993 Site Quality Assurance (SQA) surveillance findings was not as thorough or comprehensive as PG&E management would expect. In response to the SQA surveillance, PG&E technical organizations continued to conclude that the SQA surveillance issues did not represent current operability concerns. This was based on engineering judgment that existing programs, described in response to Generic Letter (GL) 89-13, effectively assured current ASW system operability. In addition, a failure by both technical and quality organizations to take adequate ownership for resolution of the concerns contributed to these events.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. A full and thorough engineering analysis and test review of heat exchanger operability has been performed (confirmatory testing on Unit 2 awaits the Unit 2 sixth refueling outage in October of 1994) to resolve all issues raised and demonstrate ASW system operability.

2. PG&E has established an Integrated Problem Response Team (IPRT) whose purpose is to perform an integrated review of the ultimate heat sink systems, including the CCW heat exchangers, and to recommend enhancements. Membership of the team is multi-departmental including members from operations, quality services, regulatory services, engineering, and Westinghouse.

3. Design engineering, system engineering and licensing personnel involved with the GL 89-13 testing, analysis, and submittal preparation were counseled on the thoroughness that must be applied when engineering judgment is used to justify acceptance of test deviations.

4. A case study describing the situation, communications, corrective actions, and management's expectations on the events surrounding the ASW heat exchanger testing was conducted with appropriate NPG personnel. The Directors of System Engineering, Mechanical Engineering, and Site Quality Assurance presented the case study. PG&E believes that by using the Directors to lead the case study, a clear message of expectations on the high standards of thoroughness, clear communication, and delineation of responsibilities were fully reemphasized to the technical staff.

5. Procedure AD1.ID1, "Format, Content and Style of Procedures," was revised subsequent to the performance of the GL 89-13 heat exchanger testing to require that comprehensive acceptance criteria be documented for special tests.

6. Equipment Control Guideline 17.2, "Auxiliary Saltwater Continuous Chlorination System," was issued to provide administrative controls on the ASW chlorination system.

7. In addition to inspections performed when the CCW heat exchanger differential pressure (dp) limits are reached, recurring work orders have been created to clean the dp lines for each CCW heat exchanger every six months.

8. Performance testing was completed on the Unit 1 CCW heat exchangers that verified the adequacy of the dp setpoint and the current maintenance program.

CORRECTIVE STEPS THAT WILL BE TAKEN TO AVOID FURTHER VIOLATIONS

1. Procedure AD13.ID1, "Conduct of Plant and Equipment Tests," will be revised to require that deviations from acceptance criteria be documented and justified prior to acceptance of the deviation.

2. The IPRT is scheduled to complete its review by December 31, 1994. After completion of the IPRT, additional design basis information will be added, as appropriate, to the relevant Design Criteria Memoranda.

3. Administrative procedures will be revised to assure timely evaluation of quality organization concerns involving potentially degraded conditions.

4. Upon completion of the Unit 2 heat exchanger performance tests scheduled for the Unit 2 sixth refueling outage, PG&E will reevaluate the CCW heat exchanger dp setpoint.

5. Enhanced ASW flow instrumentation will be installed with local readouts.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Based on a comprehensive review of the design basis, maintenance programs, and test results for the CCW heat exchangers, PG&E considers this system to be operable and capable of meeting its design basis requirements. Procedure AD13.ID1 will be completed by September 9, 1994. The IPRT will complete its review by December 31, 1994. Reevaluation of the dp setpoint will be completed by December 31, 1994. Installation of enhanced ASW flow instrumentation with local readouts will be completed by June 30, 1995.

February 6, 1997

PG&E Letter DCL-97-018

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

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Request for Information Pursuant to 10 CFR 50.54(f) Regarding
Adequacy and Availability of Design Basis Information

Dear Commissioners and Staff:

On October 9, 1996, the NRC issued a letter to PG&E entitled "Request for Information Pursuant to 10 CFR 50.54(f) Regarding Adequacy and Availability of Design Basis Information." In the letter, the NRC requested several categories of information related to design basis and configuration control. The NRC required a written response under oath or affirmation within 120 days of receipt of the letter. This letter provides PG&E's response to the NRC request.

At my direction and in my capacity as Senior Vice President - Nuclear Power Generation and senior nuclear officer, PG&E has performed an extensive review of the design control and configuration management processes at Diablo Canyon Power Plant, Units 1 and 2 (DCPP). The results of this review provide confidence that DCPP is being maintained and operated in accordance with its design bases as defined in 10 CFR 50.2.

PG&E recognizes the importance of adherence to the design bases and proper maintenance of configuration control during all aspects of operation of DCPP. While the reviews that were conducted in the development of this response did not identify the need for major improvement activities at DCPP, these efforts have heightened personnel awareness and reinforced PG&E management's commitment to conformance with the design and licensing bases. The specific details of PG&E's activities related to ongoing design and configuration control at DCPP are provided in the enclosure.

In this review, PG&E identified several actions that it plans to take to ensure conformance at a greater level of detail with the DCPP design bases. These actions include: (1) additional training of DCPP staff in the areas of design and configuration control, Final

Safety Analysis Report (FSAR) Update, and 10 CFR 50.59 evaluations; (2) further detailed review of the FSAR Update licensing basis information; and (3) selected review of operating and maintenance procedures against design basis documentation. Based on results from these actions, PG&E may perform additional "vertical-slice" assessments. These actions are discussed in further detail in the enclosure.

I have personally reviewed the enclosure in its totality and assured myself that it provides the information requested in the October 9, 1996, NRC letter.

Sincerely,

/s/
Gregory M. Rueger

Subscribed and sworn to before me this
6th day of February 1997
County of San Luis Obispo

Attorneys for Pacific Gas and
Electric Company
Bruce R. Worthington
Richard F. Locke

/s/ Amy J. Calloway
Notary Public

/s/
Richard F. Locke

cc: Steven D. Bloom
L. J. Callan
Kenneth E. Perkins
Michael D. Tschiltz
Diablo Distribution

Enclosure

JET/1990

Pacific Gas and Electric Company

Diablo Canyon Power Plant Design Basis Configuration Management Affirmation

PG&E

2/6/97

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This enclosure provides PG&E's response to the NRC's request for information pursuant to 10 CFR 50.54(f), dated October 9, 1996, regarding conformance of PG&E's Diablo Canyon Power Plant (DCPP) to its design bases. In the October 9 letter, the NRC noted that based on recent inspections at some plants, it had identified programmatic weaknesses that had resulted in design and configuration deficiencies. The magnitude and scope of the problems raised NRC concerns about the presence of similar design, configuration, and operability problems, and about the effectiveness of quality assurance programs at other plants. The NRC determined that it required information from licensees to address these concerns, and issued letters to licensees requesting the information necessary to evaluate design basis adequacy.

The NRC request includes several categories of information related to design basis and configuration control. Specifically, the NRC requests that PG&E provide:

(a) *Description of engineering design and configuration control processes, including those that implement 10 CFR 50.59, 10 CFR 50.71(e), and Appendix B to 10 CFR Part 50;*

(b) *Rationale for concluding that design bases requirements are translated into operating, maintenance, and testing procedures;*

(c) *Rationale for concluding that system, structure, and component configuration and performance are consistent with the design bases;*

(d) *Processes for identification of problems and implementation of corrective actions, including actions to determine the extent of problems, action to prevent recurrence, and reporting to NRC; and*

(e) *The overall effectiveness of your [PG&E's] current processes and programs in concluding that the configuration of your [PG&E's] plant(s) is consistent with the design bases.*

In addition, the NRC requests that PG&E indicate whether it has undertaken any design review or reconstitution programs and, if so, that it provide any supporting information.

In developing this response, PG&E reviewed the existing documentation of its configuration control processes and the results of these processes as exhibited in the performance of selected plant systems and programs. Nearly 1,000 documents relevant to design bases and configuration control processes were reviewed and analyzed in this effort, including audit and assessment reports and NRC inspection reports.

Historical Perspective

PG&E recognizes the importance of operating and maintaining DCPP within its design bases and of ensuring that deviations are reconciled in a timely manner. To achieve these objectives, PG&E has established formal controls for activities that may affect plant design and configuration. These controls have evolved over the life of the plant, and have been enhanced based on experience gained through past occurrences at DCPP as well as through industry experience and NRC observations.

In contrast with many other licensees, PG&E was its own architect/engineer (A/E) for the design and construction of DCPP. As the A/E, PG&E staff was extensively involved with the details of DCPP's design bases since well before the plant was licensed to operate. This continuity has contributed to PG&E's familiarity with the design basis history of DCPP and to an understanding of the documentation available and tools necessary for ensuring design and configuration control.

Since initial licensing, PG&E has been sensitive to the importance of ensuring the effectiveness of design and configuration control programs. An early occurrence of improper design control -- the so-called "mirror image" design error, which was discovered by PG&E immediately following initial licensing of DCPP Unit 1 in 1981 -- reinforced the need for vigilance in addressing design issues. Following that discovery, the NRC suspended the Unit 1 license and mandated an Independent Design Verification Program (IDVP) as a condition for reinstating the license. In response to the IDVP, PG&E performed a comprehensive design review effort that required extensive resources and took several years to complete. While the seismic design adequacy of the plant was firmly established by this effort, lessons learned identified necessary improvements to the design and configuration control practices at the time, and they continue to reinforce PG&E's commitment to maintain such controls and to ensure their effectiveness. In short, PG&E learned firsthand the significant price that can be paid if plant design is not properly managed and controlled.

To ensure the effectiveness of design and configuration control processes, PG&E has required that plant systems and control processes be subjected to both internal reviews and independent assessments throughout the life of the plant. Internal reviews have included the original design review; additional checks performed to support subsequent design changes; audits performed by the QA organization; and self-assessments performed by various departments. Independent assessments by external organizations include inspections by the NRC and other industry organizations. In particular, the design and configuration of safety-related systems at DCPP have been reviewed on many occasions through such assessments. Overall, these reviews have contributed to better documentation of the design and to enhanced understanding of the design bases.

Over the years, the aforementioned reviews identified weaknesses in certain of the design and configuration control processes, causing PG&E to undertake several initiatives. For example,

several major programs were conducted in the late 1980s to improve the effectiveness of design and configuration controls at DCPP. One of the most important of these programs was the Configuration Management Program (CMP), which included a number of initiatives aimed at improving design and configuration control practices at DCPP. As a result of these initiatives, PG&E is confident that the necessary and appropriate design and configuration controls are currently in place.

The continued operation and maintenance of DCPP involves many extensive and complicated design and configuration control activities. In the face of these on-going challenges, it would be unrealistic to believe that problems will not occur and that the need for additional enhancements to existing programs and processes will not be encountered. The existing controls have evolved based upon extensive experience gained at DCPP and throughout the industry, and PG&E believes that these controls are adequate to provide continued confidence that DCPP is being operated and maintained within its design bases.

Overall Approach to Design and Configuration Control

PG&E's belief that DCPP is built, maintained, and operated consistent with its design bases rests on the fact that it has in place the proper tools, the processes that help to ensure the correct use of these tools, the skilled and experienced personnel to effectively implement the processes, and the continuing oversight and verification from audits and inspections to prevent significant deviations from its design bases.

PG&E developed various tools to assist DCPP personnel in documenting and maintaining plant design, design changes, and other pertinent design basis information. These tools include: (1) enhanced Design Criteria Memoranda (DCMs) (typically referred to in the industry as design basis documents), which allow easy identification of design basis information; (2) various databases to track equipment, components, and procedure revision commitments; (3) programs for materials procurement and spare parts control; (4) a computerized plant information management system (PIMS); and (5) a computerized document library system for DCMs and other key design-related documentation. The CMP, which was conducted from 1989 to 1994, collected the pertinent design basis information into a single set of documents; provided easy access to design documentation; and verified the functionality of the various design control processes.

PG&E has instituted and proceduralized the key processes that specify and control the necessary actions and responsibilities that may affect plant design or configuration management. These key processes control the core design activities, such as design calculation practices; system and equipment setpoints; procurement; operational practices; and other plant work that involves plant design or configuration management.

Executive Summary

PG&E has dedicated significant resources to obtaining and maintaining highly qualified personnel who can effectively use their experience, capabilities, tools, and processes to effectively maintain consistency between the design bases and the plant and its documentation. The qualifications of the staff are continually updated and tested by a comprehensive training program.

PG&E has in place a quality assurance (QA) program that provides for the periodic verification, through audits or similar assessments, of the effectiveness of design and configuration control practices. The QA program includes processes for identification and resolution of design-related problems as well as "vertical-slice" audits and other assessments of design and configuration control processes. For instance, PG&E has implemented 18 vertical-slice audits to assess the effectiveness of existing controls, such as Safety System Functional Audit and Reviews (SSFARs) and Safety System Outage Modification Inspections (SSOMIs), patterned after the NRC's corresponding programs.

Beyond the tools, processes, people, and checks described above, another significant factor that is important to maintaining the consistency of the plant with its design bases is PG&E management's commitment to the proper control of design basis information and to a safety culture that continues to rigorously evaluate and maintain the design bases during operation.

While none of these factors alone would be sufficient to provide the required confidence in DCPP's design bases and configuration control processes, taken together they provide confidence that there is an organized, systematic, and effective approach to ensure consistency with the design bases at DCPP. Moreover, the findings from reviews of these various programs and controls, along with problem resolution efforts, provide a clear indication of the effectiveness of these programs and the strong desire to continuously improve the overall design and configuration control processes.

PG&E recognizes that DCPP is a highly complex combination of equipment, systems, programs, and people. Problems can be expected to arise periodically in such an enterprise. However, PG&E believes that when problems are identified, they are resolved through an effective corrective action process. While PG&E cannot unequivocally rule out the presence of inconsistencies with DCPP's design bases, it is confident that overall the plant remains within its 10 CFR 50.2 design bases.

PG&E's rationale for reaching these conclusions regarding the effectiveness of the existing design and configuration controls is explained in response to each of the requests in the NRC's October 9, 1996 letter. These responses are summarized below.

Specific Responses

(a) Design and Configuration Control Processes

PG&E has in place at DCPP procedures that implement processes for engineering design and configuration control. These procedures collectively contain the necessary attributes to maintain engineering design and configuration control. The design change processes employed at DCPP provide for the appropriate development and evaluation of design changes so that the design bases are maintained, as well as for the communication of design change impacts to operating, maintenance, testing, and other support staff organizations. Moreover, the processes for revision of procedures also require a review of the design basis and licensing basis documentation to ensure that the design bases are maintained. Finally, these processes specifically implement the requirements of 10 CFR 50.59, 10 CFR 50.71(e), and Appendix B to 10 CFR 50.

Based on a review of internal assessment reports and NRC inspection reports, PG&E believes that these processes have been implemented in a manner that maintains design and configuration control. At the same time, PG&E recognizes that there have been instances where design-related problems have been identified over the years. However, when such problems have been identified, PG&E has evaluated them and has implemented corrective actions that not only addressed the specific problems, but also strengthened the related processes. Relatively few major issues have been identified since commercial operation and they have not reflected a significant programmatic failure. Nonetheless, they demonstrate the need to remain vigilant and to continually monitor performance in this area.

(b) Design Basis Translation to Operating, Maintenance and Testing Procedures

PG&E has processes for ensuring that DCPP design basis requirements have been properly translated into operating, maintenance, and testing procedures. PG&E believes that these processes have been effective based on several factors. First, the procedures were developed by PG&E's plant staff from the original design bases through interactions between PG&E's Engineering staff, vendors, and contractors. Second, Technical Specifications and operating guidelines that reflect the design bases have been thoroughly reviewed, and are used as a key input to operational activities. Third, following initial development of these procedures, the control processes for procedure changes have provided the necessary attributes to ensure consistency between the procedures and design basis requirements. Fourth, DCM and setpoint enhancement programs have included design basis reviews of plant procedures. Finally, the extensive audits and assessments that have been performed over the years since DCPP has been in operation have found these processes to be effective in maintaining consistency between procedures and design bases.

(c) System, Structure, and Component Configuration, and Performance Consistency

The complicated and lengthy licensing history of DCPP included an extensive preoperational and startup testing program and verification activities that validated configuration and performance consistency with the design bases of the plant. Following commencement of commercial operation and as part of normal operating and maintenance activities, plant personnel routinely have monitored the configuration and operational characteristics of plant systems, structures, and components. Various programs related to configuration control and plant performance, such as the DCPP System Engineering program and implementation of Generic Letters 89-10 and 89-13, provide additional assurance of configuration and performance consistency with design bases. Periodic system and component testing has been performed to demonstrate that plant performance remains within acceptable parameters. Frequent audits and surveillances have been performed to ensure that structure, system, and component configuration, and performance are consistent with the design bases.

(d) Processes for Problem Identification and Resolution

PG&E has reviewed its processes for identification and resolution of problems associated with design issues. PG&E recognizes that these processes are crucial to ensuring that the plant configuration and design bases are being maintained. Accordingly, PG&E has critically reviewed the processes for identifying problems, determining the significance of these problems, resolving the problems, preventing their recurrence, and reporting these problems to the NRC. PG&E believes that these problem identification and control processes have functioned properly and effectively in maintaining design and configuration control.

The original QA program, as approved by the NRC in licensing DCPP, contained PG&E's processes for the identification and resolution of problems. During the ensuing years of operation, these processes have been enhanced significantly. The primary enhancements included (1) refinement of various problem reporting and resolution mechanisms, (2) improvement of problem evaluation and root-cause determination methods, (3) implementation of vertical-slice audits such as SSFARs and SSOMIs, and (4) continuing training of personnel who perform audits and assessments. Many of these enhancements were implemented as a result of findings and observations from PG&E's own audits, assessments, and initiatives; some came as a result of industry developments, and others resulted from an evolution in NRC guidance and requirements.

PG&E concludes that its processes for problem identification and resolution are sound, effective, and well-structured. The self-critical nature of these processes provides valuable insight into the overall viability of the existing programs for design and configuration control, and provides assurance that PG&E is operating and maintaining DCPP in conformity with its design bases. Based on these results, PG&E believes that these problem identification and resolution processes

can and will continue to identify and resolve issues that may involve design basis consistency and configuration management.

(e) Overall Effectiveness of Processes and Programs for Configuration Management

PG&E believes its current processes and programs are effective in maintaining plant configuration consistent with the 10 CFR 50.2 design bases and in providing the necessary feedback to PG&E management. PG&E's processes for design and configuration control have been thoroughly assessed and found to be functioning adequately. In the vast majority of cases where verification efforts have been undertaken, plant design bases have been determined to be accurate; applicable design requirements have been properly translated into operating, maintenance, and testing procedures; and DCPP's system, structure, and component configuration and performance have been maintained consistent with its design bases. Furthermore, many design changes have been performed on major plant systems, providing additional opportunities for a thorough review of the design bases, training, and associated maintenance, testing, and operating procedures. Problems that have been identified in design and configuration control have been rectified and the processes and programs improved.

Design Basis Documentation and Review Program

Over the years, PG&E has sought to improve its assessment and control processes and has taken a proactive role in developing methods for improving design and configuration control. The CMP, which evolved from a combination of NRC, industry, and internal reviews, was established as a major program to accomplish the necessary improvements. For example, a CMP element of particular relevance to the current NRC concern was PG&E's effort to enhance its DCMs. The DCM enhancement effort, which involved some 89 system and topical areas, was implemented by PG&E to address design basis issues identified during the course of plant operation. More specifically, the DCM enhancements involved reformatting original DCMs into a more complete compilation of various design bases. In addition, the enhanced DCMs clarified references to sources of design basis information so that the information could be more easily verified if necessary. As part of this activity, PG&E reviewed the design basis information in design, maintenance, testing, and operation procedures, processes, and programs.

Conclusions and Future Actions

PG&E is confident that, as implemented, the design and configuration control processes at DCPP provide reasonable assurance that the plant is maintained and operated in accordance with its design bases as defined in 10 CFR 50.2. In addition, while activities conducted in the development of this response did not result in the identification of the need for major improvement activities at DCPP, they have heightened personnel awareness and have reinforced management commitment to conformance with design and licensing bases.

PG&E has identified additional actions that it plans to take to further improve its ability to maintain conformance with the DCPP design bases. These actions include additional licensing documentation review (Final Safety Analysis Report (FSAR) Update) and further training in the areas of configuration management, FSAR Update, and 10 CFR 50.59 evaluations. These actions also include further DCM reviews of procedures and continuing focused quality assurance audits to assess PG&E's performance in ensuring conformance with the DCPP design bases.

INTRODUCTION

On October 9, 1996, the NRC issued a letter to PG&E entitled, "Request for Information Pursuant to 10 CFR 50.54(f) Regarding Adequacy and Availability of Design Basis Information." The NRC required a response within 120 days of receipt of the letter. This enclosure provides PG&E's response to the NRC request.

In its October 9 letter, the NRC stated that recent "*inspections and reviews have identified broad programmatic weaknesses that have resulted in design and configuration deficiencies at some plants.*" These inspections and reviews also highlighted instances in which timely and complete implementation of corrective actions for known degraded and nonconforming conditions, and for past violations of NRC requirements, had not been evident. The magnitude and scope of the problems identified raised NRC concerns about the presence of similar design, configuration, and operability problems, and about the effectiveness of quality assurance programs at other plants. Further, the NRC expressed concern about whether licensee programs to maintain configuration at their plants are sufficient to demonstrate that plant physical and functional characteristics are consistent with and are being maintained in accordance with their design bases. The NRC concluded that it required information from licensees to address its concerns, and issued similar letters to all licensees requesting the information necessary to evaluate design basis adequacy.

Specifically, the NRC's October 9 letter requested that PG&E provide the following information for each unit at Diablo Canyon:

(a) *Description of engineering design and configuration control processes, including those that implement 10 CFR 50.59, 10 CFR 50.71(e), and Appendix B to 10 CFR Part 50;*

(b) *Rationale for concluding that design bases requirements are translated into operating, maintenance, and testing procedures;*

(c) *Rationale for concluding that system, structure, and component configuration and performance are consistent with the design bases;*

(d) *Processes for identification of problems and implementation of corrective actions, including actions to determine the extent of problems, action to prevent recurrence, and reporting to NRC; and*

(e) *The overall effectiveness of your [PG&E's] current processes and programs in concluding that the configuration of your [PG&E's] plant(s) is consistent with the design bases.*

In addition, the NRC letter requested that PG&E indicate whether, in responding to items (a) through (e), it has *"undertaken any design review or reconstitution programs"* and, if so, provide supporting information.

In the following sections, PG&E provides specific responses to each of the areas of information requested in the NRC letter. Where the information furnished applies to more than one section of the response, cross-referencing is provided to avoid undue repetition. One response is provided for Diablo Canyon Power Plant (DCPP) Units 1 and 2, since the two units essentially are identical and are described in the same design and licensing documents, including the DCPP Final Safety Analysis Report (FSAR) Update, the Technical Specifications, and internal design criteria documents at PG&E. While there are differences between the two units because of, for instance, original design, timing of modifications to each unit, or procedural details in operation and maintenance, the same processes have been in effect and continue to be applied in implementing design and configuration control at both units.[1]

The specific responses to each NRC request have been developed based on a review of the following areas:

(1) Processes that implement design and configuration control

(2) Processes for problem identification and corrective action

(3) Selected operating, maintenance, and testing procedures, with regard to compliance with design basis documents

(4) Selected system and topical areas in plant operation

(5) History of internal and external audits and assessments, relative to evaluation of design and configuration management control

With the exception of the review of a few selected operating, maintenance, and testing procedures, no new audits, assessments, or inspections were performed in developing this response. Thus, the bulk of the supporting data for this response comes from previous or existing programs. This approach is considered reasonable given PG&E's history of having conducted several significant reviews that evaluated program compliance and that provide confidence of compliance with DCPP design and licensing bases. Programs that relate to design or configuration control include: (1) the Hosgri seismic reevaluation program; (2) the Independent Design Verification Program (IDVP); (3) the Long Term Seismic Reevaluation Program (LTSP); and (4) the Configuration Management Program (CMP), as well as the development of detailed procedures for design changes and configuration control. In addition, PG&E has performed five Safety System Functional Audit and Reviews (SSFARs) and 13 Safety System Outage and Modification Inspections (SSOMIs), which provided a "vertical-slice" audit perspective, to verify the effectiveness of these programs. The NRC also has performed its own vertical-slice type

[1] The definitions of various key terms important to design bases and configuration management, as used at DCPP and in this submittal, are provided in Appendix C, Definitions.

inspection that assessed the effectiveness of PG&E's configuration management programs. Finally, PG&E has performed more than 4,000 design changes since 1989 on a number of important systems. The associated design review process provided another critical review.

PG&E has continuously improved its processes and has often taken a proactive role in developing methods for improving design and configuration control. For instance, in 1988 the CMP was established: (1) to provide design basis information in a more accessible and useful format for PG&E staff; (2) to increase overall knowledge of the design bases; and (3) to ensure that compliance with the design bases is maintained in plant operation. Additional details on this program are discussed in Section (b), Design Basis Translation to Operating, Maintenance, and Testing Procedures, and Section (f), Design Basis Review and Documentation Program. PG&E recognizes the importance of these controls, and will continue proactive efforts to ensure conformance with design bases during future plant operation.

Background and Licensing History

Before responding to the specific NRC requests, the following discussion of the background and licensing history of DCPP is provided. During this time, significant reviews and strengthening of DCPP's consistency with its design bases have occurred. This history also provides information pertinent to placing PG&E's current programs into a proper perspective.

During the licensing of DCPP, several evaluations of various aspects of the design and design bases were performed following completion of the initial design. These evaluations were conducted by PG&E and independent engineering organizations, as well as by the NRC, and occurred periodically after the completion of the original plant design in support of the DCPP operating license application originally filed in 1973. These evaluations consisted of major programs that took years to complete and that required extensive resources. This history of DCPP is briefly summarized below.

Initial Licensing and Hosgri Seismic Reevaluation

The construction permits for DCPP Units 1 and 2 were issued in 1968 and 1970, respectively. Much of the initial design bases for the plant were established at that time in support of the operating license application. During the initial period following Unit 1 construction, the systems and components were integrated and thoroughly tested to demonstrate functional capability over a limited range of operating conditions. The original FSAR for DCPP was issued in 1973 in support of the application for the operating licenses for DCPP Units 1 and 2.

Unit 1 essentially was completed in 1976 and ready for operation at that time. However, because of concerns relating to the adequacy of the seismic design criteria for DCPP that surfaced subsequent to the discovery of the Hosgri Fault in the early 1970s, issuance of the operating licenses was delayed while the NRC evaluated additional seismic design information.

Discussions occurred between the NRC and PG&E staff with respect to the appropriate seismic criteria and the seismic capability of the plant. As a result of these discussions, additional analyses of plant systems, structures, and components, and associated plant modifications, were completed. PG&E's documentation of the Hosgri seismic reevaluation consisted of seven volumes of technical reports that were submitted to the NRC in the 1976 to 1979 time frame. Because of the analytical and physical work required, the overall impact of the Hosgri reevaluation was to improve the consistency of DCPP with its seismic design bases.

Impact of Three Mile Island

In 1979, DCPP Unit 1 was essentially complete and ready for operation. However, the event at Three Mile Island (TMI) caused a delay in the licensing of nuclear power plants in the United States, including DCPP. During this delay, the NRC reevaluated the design bases for DCPP. PG&E addressed the numerous issues identified by the NRC as a result of the TMI event. Resolution of these issues required additional analyses, plant modifications, and procedure changes, which provided further opportunities to improve consistency with design bases.

During this period, PG&E also addressed several other generic NRC concerns that provided confidence that DCPP was conforming to design basis details that the NRC had specified in additional regulatory guidance. These concerns included piping design (in NRC Bulletins 79-02, 79-04, and 79-14), fire protection (10 CFR 50.48 and Appendix R), and environmental qualification (10 CFR 50.49). After completing actions to satisfy the NRC concerns, DCPP received a low-power operating license for Unit 1 in September 1981. Eight volumes of PG&E reports relating to TMI issues were submitted to the NRC during the 1979 to 1984 time frame. The NRC staff's evaluations supporting approval of the license were documented in the original and Supplemental Safety Evaluation Reports (SSERs) 1 through 15 for DCPP.

Independent Design Verification Program (IDVP)

Immediately after issuance of the low-power license for Unit 1 on September 22, 1981, PG&E discovered a design implementation error, immediately reported it to the NRC, and suspended fuel loading activities. This discovery resulted in the suspension (in November 1981) of the Unit 1 low-power license and postponement of Unit 2 licensing. The NRC required an IDVP for both units as a prerequisite to reinstatement of the operating license for Unit 1. The IDVP was developed, conducted, and managed by an independent consultant.

Concurrent with the IDVP, PG&E implemented an Internal Technical Program (ITP). The purpose of the ITP was to efficiently respond to the findings of the IDVP and to complete a thorough review of structural design. Thus the elements of the IDVP and the ITP, which together formed the DCPP Design Verification Program (DVP), provided added assurance that the plant conformed with its design and licensing bases. More than 10 volumes of program documents and several dozen supporting technical reports from these programs were submitted to the NRC.

The Unit 1 low-power license was reinstated in stages beginning in November 1983. The NRC's review of the IDVP was documented in the 1983 to 1984 period in SSERs 18, 19, 20, and 24. The IDVP results were also reviewed by the NRC's licensing boards as well as by the Advisory Committee on Reactor Safeguards.

The NRC reviewed the results of the ITP and the IDVP and concluded that the IDVP had been completed successfully and that there was reasonable assurance that the plant met the conditions of the license. The Unit 1 full-power operating license was issued in November 1984, and commercial operation was achieved in May 1985. Unit 2 received its operating license in 1985 and achieved commercial operation in 1986. Figure 1 presents a timeline of the key licensing milestones, internal programs, and industry events relevant to this discussion. Additional details on the IDVP and the DVP are provided in Section (c), System, Structure, and Component Configuration and Performance.

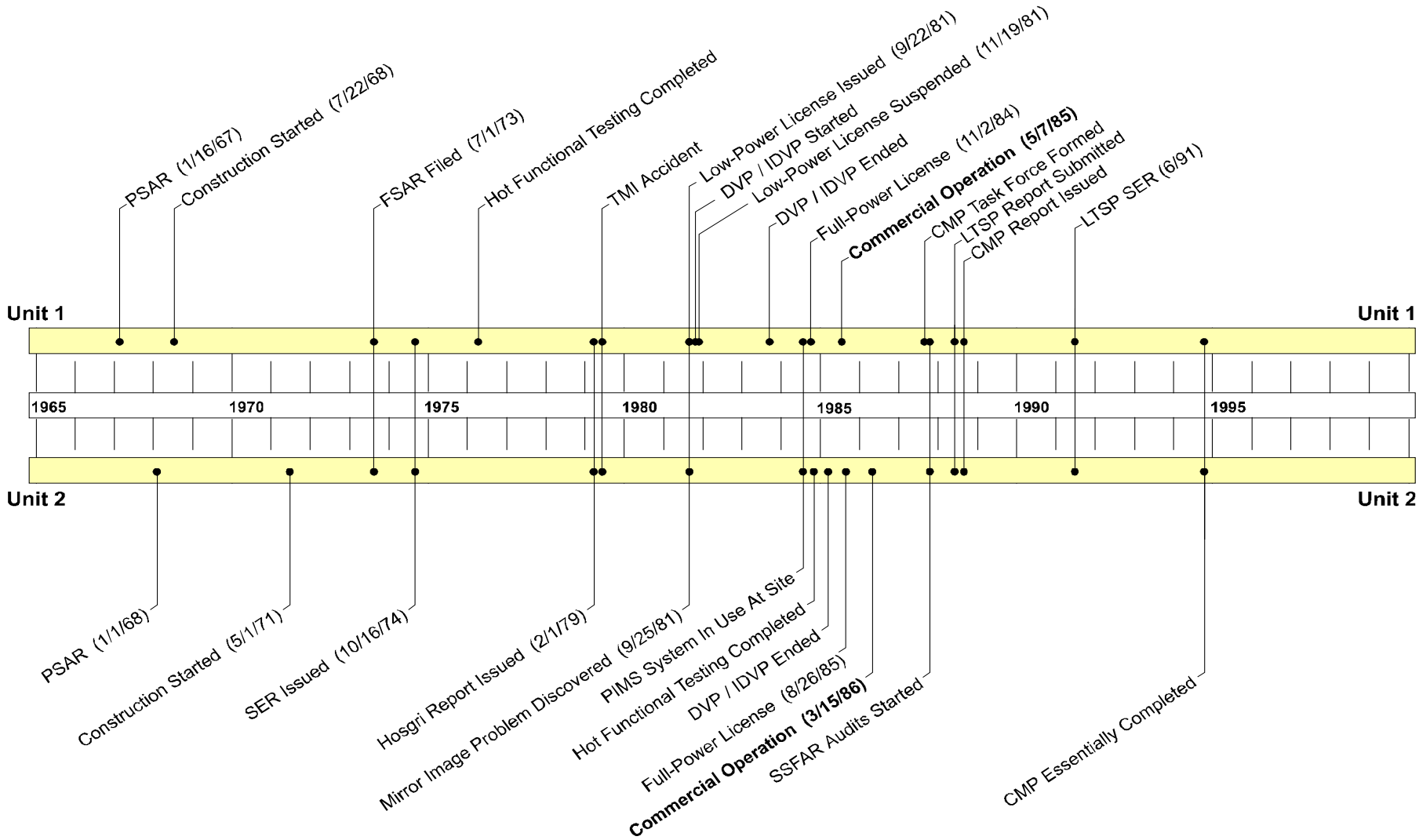
As a result of this prolonged licensing process, the initial FSAR Update (Revision 0) required by 10 CFR 50.71(e) for DCPP was issued in 1984. Subsequent revisions have been issued thereafter in accordance with regulatory requirements.

Long Term Seismic Program (LTSP)

In reinstating the Unit 1 license in November 1983, the NRC imposed a license condition requiring that PG&E conduct an LTSP to reevaluate the seismic design bases for DCPP. PG&E conducted the LTSP review between 1985 and 1988, and the results of the program reconfirmed the adequacy of the seismic design and seismic margins for the plant's systems, structures, and components. The LTSP Final Report was submitted in July 1988 as required by the license. The NRC conducted a three-year review of the LTSP Final Report and issued its approval of the LTSP in 1991 in SSER 34, wherein the NRC staff concluded that "*The LTSP has served as a useful check on the adequacy of the seismic [design] margins and has generally confirmed that the margins are acceptable*."

In addition, and as a direct result of the LTSP, PG&E was among the first licensees to develop and use a probabilistic risk assessment (PRA) program to aid in assessing plant operational safety. The NRC staff noted this fact in SSER 34 stating that "*The PRA methodology used represents state-of-the-art methodology, and in many cases has advanced the state of the art*." This PRA model has been updated regularly and has contributed to other PG&E activities relevant to design, such as responding to the NRC's requirements on Individual Plant Examination (IPE). In addition, PRA insights are integrated into plant activities in operation, maintenance, and outages.

Figure 1: DCPP Licensing, Construction & Operation Timeline



Commercial Operation

Prior to and following commercial operation of Units 1 and 2 in 1985 and 1986, respectively, various programs and initiatives were implemented at DCPP that involved design basis and configuration management enhancements. In the early to mid-1980s, these efforts included actions to upgrade the control of design basis information through several mechanisms, such as plant as-built documentation enhancements; design and design change procedure improvements; more detailed design criteria, procedures, and design documentation; and revised construction and maintenance practices to support the other improvements.

In the mid- to late 1980s, PG&E's design and configuration control improvement efforts included the establishment of a formal, simplified replacement parts program; the development of more explicit and extensive construction and maintenance quality control procedures; and the enhancement of the design and safety reviews performed for each design change to the plant. During this time, PG&E also formally instituted the Plant Information Management System (PIMS), a computerized system used on a daily basis to implement and monitor information related to nearly all plant activities including, for example, design, modifications, maintenance, testing, and operations.

In the late 1980s, PG&E performed several SSFARs and SSOMIs for a number of the significant safety-related systems. As a result of the findings from these vertical-slice audits, as well as from concurrent NRC activities, PG&E management recognized the need to have plant design and configuration control information more readily available during operation. Consequently, the CMP was established in 1988 to provide a focused effort to enhance configuration management. The CMP resulted in the creation of 89 separate Design Criteria Memoranda (DCMs, referred to generally as design basis documents in the rest of industry) for all safety systems, numerous nonsafety systems, and other topical areas. In addition, the CMP included the enhancement of the design change, setpoints and vendor manual control processes. While the CMP was essentially completed in 1994, the programs initiated during that period remain as important and evolving parts of PG&E's configuration management program today.

Along with these efforts, additional activities were implemented at DCPP as specific issues were identified by operational experience, the NRC, or by other industry efforts. For example, PG&E led the development of the Region V Engineering Managers Forum Design Bases Guide (a significant input to NUMARC 90-12, "Design Basis Program Guidelines," Ref. 5.29); actively participated in the Technical Specification Improvement Program for Westinghouse plants; and led Region V in upgrading design basis documentation. As mentioned earlier, PG&E was among the first licensees to develop a PRA program and has pursued the use of PRA in areas relevant to design, including the IPE program. Other activities included implementation of a system engineering program; ongoing efforts to further improve the design basis-related training; and plant improvement projects, such as installation of the Eagle 21 process protection system and addition of a sixth emergency diesel generator.

Collectively, these activities have increased PG&E's confidence in the reliability, operability, and maintainability of plant systems, as well as forcing reexamination of the design bases. Additionally, efforts continued in other areas relevant to plant design and configuration control, such as motor-operated valve performance, equipment qualification, and fire protection. By remaining current on industry and NRC developments, PG&E has been able to enhance its programs and processes for maintaining design basis and configuration control.

Preparation of This Response

In developing this response, PG&E staff conducted a retrospective review of existing documentation of configuration control processes and the results of these processes. Nearly 1,000 documents relevant to design bases and configuration management processes were reviewed. These documents included: (1) selected plant procedures for operation, maintenance, and testing; (2) administrative procedures for design and design changes, as well as configuration control; (3) licensee event reports (LERs) since 1987; (4) nonconformance reports (NCRs) since 1987; (5) Design Criteria Memoranda (DCMs); (6) internal assessments and audit reports; (7) NRC inspection reports (IRs) and notices of violation since 1987; (8) NRC safety evaluation report (SER) and supplements; (9) program reports from the IDVP; and (10) various other program and results documents. This review focused on the adequacy of design and configuration management processes as demonstrated in DCPP documents since the late 1980s, such as the design control process and the FSAR updating process. PG&E's review of this selected documentation, summary information, and conclusions formed the majority of the support for this response.

A similar review was performed for several specific plant systems and topical areas to demonstrate the adequacy of the design bases and configuration management processes in achieving appropriate design control and configuration management. This review was conducted to determine whether conclusions reached in the above program examinations were valid when measured from the perspective of the capability of a system or structure to meet its design basis requirements. The systems and topical areas reviewed included the auxiliary feedwater system, the emergency diesel generators, and the fire protection program. Based on review of this selected documentation, PG&E assembled summary information, conclusions, and an overall rationale for response to the NRC request. This information further demonstrated the adequacy (and shortcomings) of existing design and configuration management processes. Again, no new audits or assessments were performed for this response; rather, the reviews primarily relied on historical information. However, PG&E did conduct a few selected new reviews of the FSAR Update and DCMs in the maintenance and operations areas.

PG&E recognizes that both technology and industry standards of quality have continually evolved over the nearly 30-year history of DCPP licensing, design, construction, and operation. Thus, some of the historical information relied upon in this response might now be considered less than adequate in detail or technology given today's perspective. Therefore, PG&E has relied in greater part on the more recent assessment activities in reaching its conclusions in this review. Nonetheless, PG&E

believes that observations based on earlier historical information relative to key design bases are useful in gaining additional insight on configuration control and the ability of systems, structures, and components to meet their intended safety functions.

The requisite reviews conducted to support PG&E's response were performed internally by a PG&E team with a working knowledge in the areas of design, operation, maintenance, and testing. Team members included system engineers, design engineers, reactor operations personnel, maintenance personnel, quality assurance personnel, as well as other plant support staff. Two directors in PG&E's Nuclear Power Generation (NPG) organization were responsible for overall direction of the reviews and development of this response, and participated full time to provide leadership and guidance to the review team. These directors had periodic meetings with the Senior Vice President of NPG to provide status updates on the review effort and to ensure that the reviews were responsive to management expectations. NPG functional managers provided management and personnel support. Other supervisory level, operational, and technical staff in NPG were involved as needed during the review effort. In addition, NPG management emphasized to the organization that the request, and the focused resources needed to respond to it, provided an opportunity to validate and also improve the existing design control and configuration management processes.

Finally, the information supporting this response received multilevel verification during development. Each specific process and system review was verified by another qualified individual who did not directly participate in the review. A Senior Review Board consisting of former PG&E executives and managers, a representative from Westinghouse, and an individual consultant was established to provide additional overview and perspective for the effort. In addition, the response was reviewed by two external members of the DCPP Nuclear Safety Oversight Committee (NSOC), as well as by PG&E's Executive Vice President of Electric Generation (who formerly served as Senior Vice President of NPG).

The discussions in the following sections provide details on the information reviewed and the justification for the conclusions that were reached. The descriptions in this enclosure represent DCPP processes as they currently exist. Accordingly, the process descriptions contained in this enclosure do not reflect any new commitments. The related improvement activities that are planned for implementation subsequent to this review are identified specifically in the "Conclusions and Future Actions" section.

(a) DESIGN AND CONFIGURATION CONTROL PROCESSES

This section provides PG&E's response to the following NRC request:

> *(a) Description of engineering design and configuration control processes, including those that implement 10 CFR 50.59, 10 CFR 50.71(e), and Appendix B to 10 CFR Part 50*

Introduction

Engineering design and configuration control for DCPP have been and continue to be maintained through the integrated requirements of many administrative programs and procedures, together referred to as "plant processes." In fact, most plant processes play some role in ensuring that design and configuration control are maintained properly. These processes are defined and controlled by the Administrative Controls Program, covered by PG&E Program Directive AD1 (Ref. 1.1).

PG&E believes that its design and configuration control processes contain the necessary attributes to properly maintain consistency between the plant, its design bases, and its operation and maintenance. This belief is based on the following factors:

(1) The processes are comprehensive and meet the requirements of 10 CFR 50 Appendix B.

(2) The processes have been refined over many years to incorporate lessons learned from past experience.

(3) Extensive audits and inspections have generally found the processes to be adequate. As mentioned above, PG&E has responded to problems that were identified by improving the processes affected and the tools that support them.

In presenting the bases for these conclusions, PG&E will provide:

(1) The background and evolution of PG&E's current processes

(2) An overview of the major process (program) areas that provide for engineering design and configuration control

(3) A more detailed description of design change processes

(4) A more detailed description of the procedure change control process

(5) A description of the processes that implement 10 CFR 50.59 reviews

(6) A description of the processes that implement 10 CFR 50.71(e), FSAR Updates

(7) A description of the processes that implement 10 CFR 50, Appendix B

(8) A discussion of other potential impacts to the design bases

(9) A description of process-related training

(10) A discussion of the overall effectiveness of the design change, procedure control, 10 CFR 50.59, and 10 CFR 50.71(e) processes

In this section, the current state of the processes is described. However, it is expected that they will continue to evolve and improve. Some discussion of history is included to the extent that it is relevant to the conclusion that operation and maintenance of the plant is in conformance with its design bases.

In addition to having well-defined processes, success depends on having capable people to implement the processes. The required capability is achieved through a combination of base educational and experience qualifications, training in the specific processes and the related tools, and a clear understanding of performance expectations. Training is briefly discussed in this and subsequent sections. PG&E's approach to provide committed, qualified personnel is further discussed in Section (e), Overall Effectiveness of Processes and Programs for Configuration Management.

Background

From 1981 to 1984, as DCPP was transitioning from construction to operation, the design control processes went through major improvements. This was coincident with the time frame when the external Independent Design Verification Program (IDVP) and the Internal Technical Program (ITP) were being performed.

Further upgrades to the design and configuration control processes occurred in the 1989 to 1993 time frame. This was coincident with the Configuration Management Program (CMP) (Refs. 5.1, 5.2) and some of the improvements were a direct result of that program. The initial improvements and the origin of the CMP were driven by increasing industry concerns with configuration management and issues as noted in NRC Inspection Report 50-275/88-15 and 50-323/88-14 (Ref. 3.15). By 1990, PG&E's processes were developed sufficiently to address current expectations relative to maintaining design and configuration control. Subsequently, significant additional improvements resulted from the Design Change Process Initiative Project (DCPIP) (Ref. 4.5), which took place in 1992 and 1993. During this project, the DCPIP team developed and implemented an improved design change process that facilitated maintaining

consistency with the design bases, while improving the effectiveness of personnel involvement in the process. As part of DCPIP, improved tools for the development of design changes were also developed.

Overview

PG&E's processes for operating and maintaining DCPP are controlled by the Administrative Controls Program as defined in Program Directive AD1 (Ref. 1.1). This program has been in place in its current form since 1994. Prior to that time, similar process controls existed in Administrative Procedures prepared by each department (e.g., Operations, Engineering, General Construction).

In the Administrative Controls Program, the highest-tier process control documents are Program Directives (PDs). The PDs are grouped by general topical categories, and apply to the entire Nuclear Power Generation organization. Each topical area may contain one or more PDs and their subordinate procedures, Inter-Departmental Administrative Procedures (IDAPs), Departmental-Level Administrative Procedures (DLAPs).[2] Some PDs may be identified as quality-related (such as inspections) and others are nonquality-related (such as project management), based on the nature of the activity described in the procedure. The Program Directive topical areas that play a significant role in maintaining design and configuration control include:

PD Topical Categories	Category Description
AD	Administrative Support
CF	Configuration Management
MA	Maintenance
OM	Organization & Management Control
OP	Operations Control
TQ	Training & Qualification
TS	Technical Support
XI	External Interface

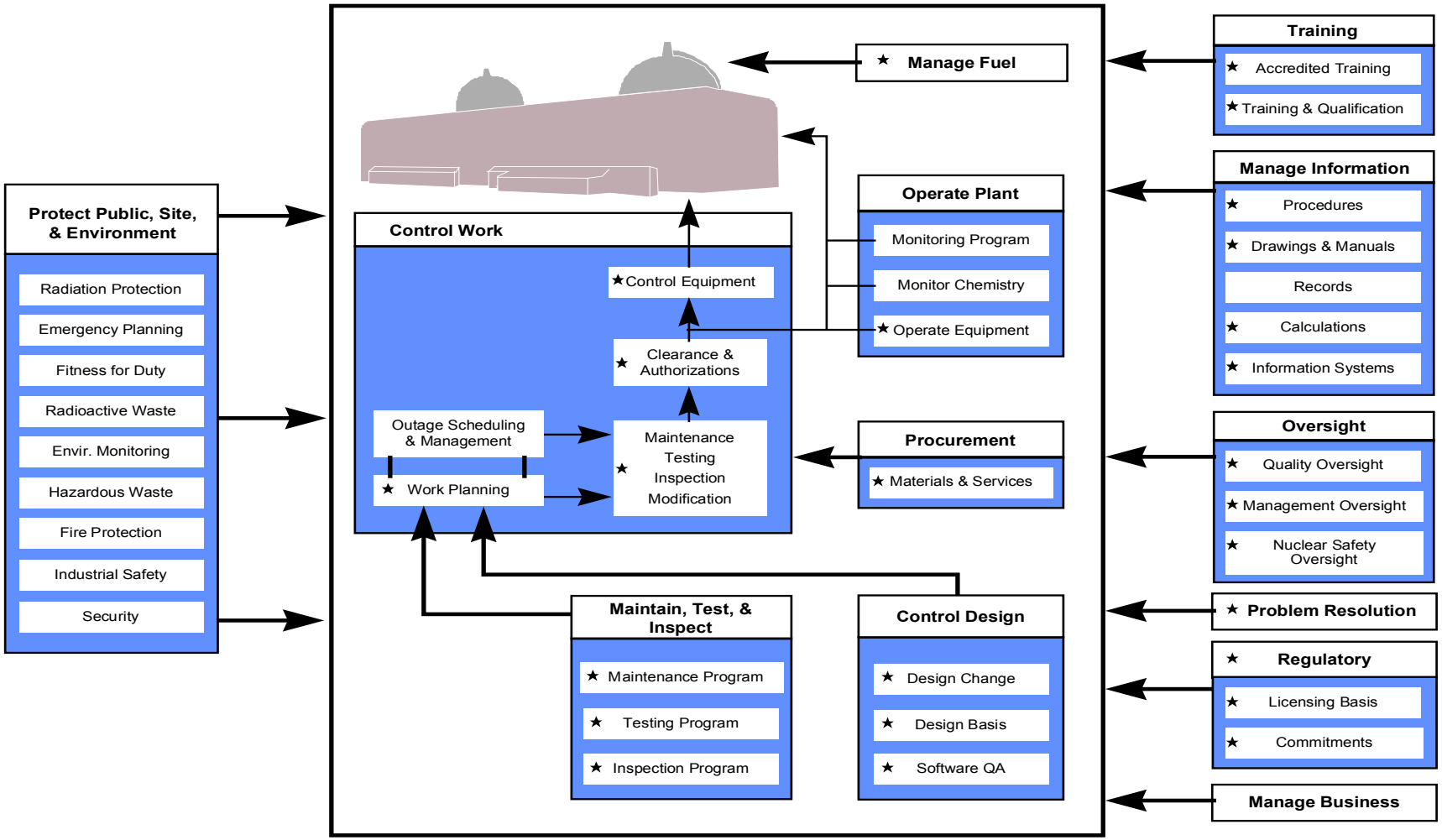
[2] Nomenclature of procedures: Program Directives are identified by a two-letter topical identifier and a numeral (e.g., AD1). IDAPs are identified by the PD number followed by the suffix “ID” and a numeral (e.g., AD1.ID1). DLAPs are identified by the PD number followed by a two-letter suffix, indicating the department, and a numeral (e.g., AD1.DC1).

Figure 2 illustrates the major process areas addressed within the DCPP Administrative Controls Program. Those process areas that have a primary role in maintaining design and configuration control are identified by an asterisk. Some of the major relationships between areas are also indicated for illustrative purposes. There are approximately 450 administrative procedures represented.

A more detailed listing of Program Directives that play a role in maintaining design and configuration control are listed in Appendix B, along with a brief description of their role. Nearly one-half of the 450 administrative procedures have some role in maintaining consistency between the design bases and the physical plant, plant documentation, operation, maintenance, and training. Figure 3 provides an overview of the general relationships that exist between the groups of processes that are key to maintaining design and configuration control. As this figure illustrates, there are many information exchange interfaces and each interface typically needs to accommodate changes that can flow in either direction. The procedures that define the details of these processes are heavily integrated.

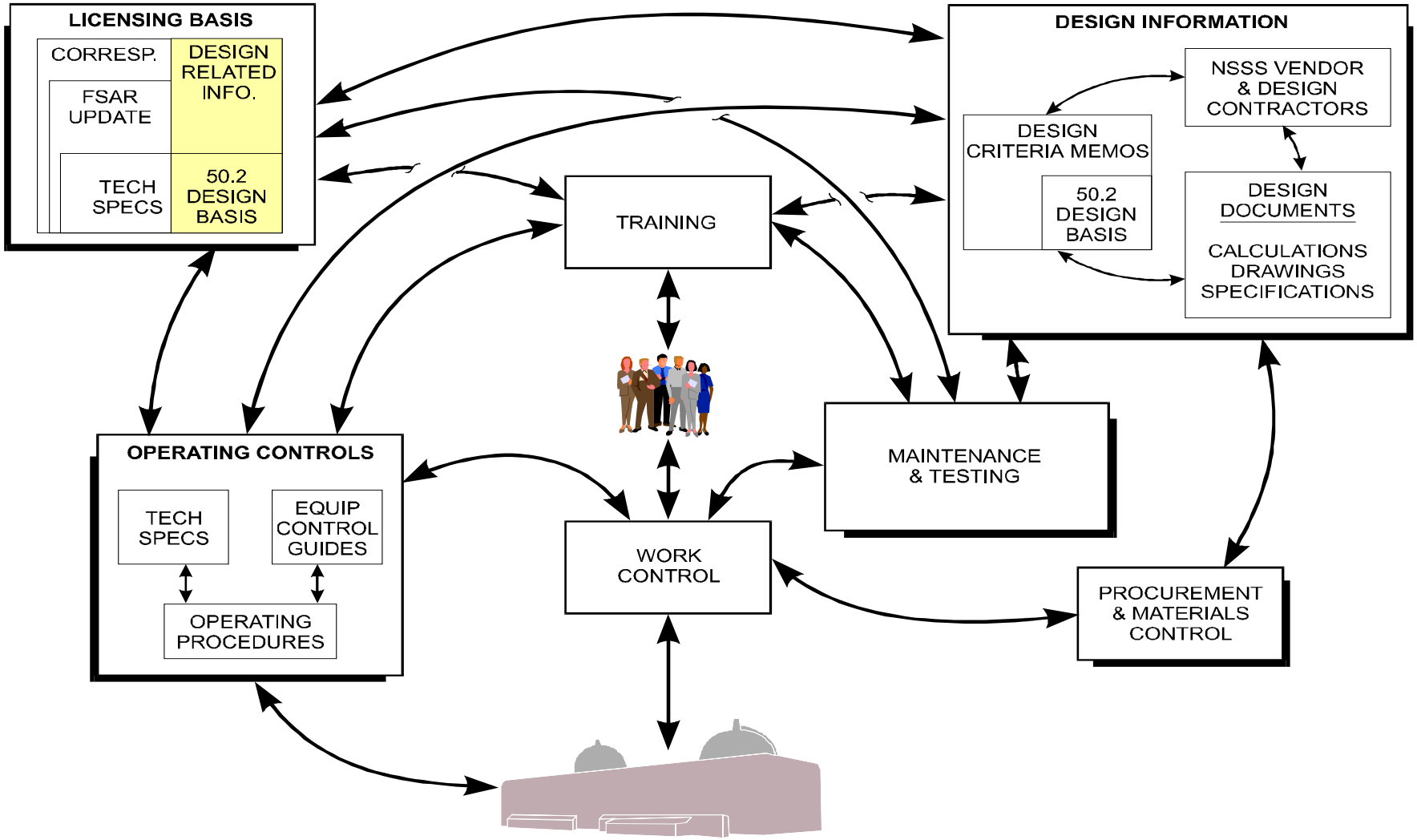
While all of these processes are important, the remainder of this process discussion will focus on several that play the most significant role in design bases and configuration control.

Figure 2: Process Area Relationships



★ **Note: Key Design and Configuration Control Related Process Areas.**

Figure 3: General Design and Configuration Control Relationships



Design Change Processes

Description

Design changes represent one of the most direct and frequent opportunities to impact the design bases and configuration of a plant. PG&E's design change processes are among the key processes that maintain design and configuration control. The DCPP design change processes are defined primarily by Program Directives on Design Control (CF3, Ref. 1.19) and Modification Control (CF4, Ref. 1.34) and their underlying Inter-Departmental and Department-Level Administrative Procedures. These processes complement one another in an integrated fashion and provide the interface with the other Program Directive areas discussed above.

The design change process as it relates to design control and configuration management is described below. The specific procedures that implement key attributes relevant to maintaining design and configuration control also are identified. They are presented in a sequence that generally matches the flow of a design change.

(1) Identification and Request. The design change process begins with the identification of the need or desire for a design change and the development of a design change request that is controlled by Procedure CF4.ID1 (Ref. 1.35). The request for design changes may arise for many reasons, including performance improvements, corrective actions for performance problems, component obsolescence, and operational experience.

(2) Management Screening and Scope Approval. Design change requests are screened by management to determine their suitability and are approved for further development (CF4.ID1, Ref. 1.35).

(3) Design Change Vehicle Selection. The next step is the selection of the appropriate design change vehicle (CF4.ID1, Ref. 1.35) for the development and processing of the design change. Several design change vehicles have been developed over the years in recognition of the fact that there are various types of changes. Each of these vehicles has been carefully developed to contain appropriate reviews, evaluations, authorizations, and documentation commensurate with the complexity and safety significance of the change to ensure that an adequate level of design and configuration control are maintained. Criteria for the selection and use of each vehicle have been established to limit their use to the appropriate type of design change. The use of any vehicle provides adequate consideration and documentation of consistency with the design bases or leads one through the steps needed to change the design bases.

The most complex changes are addressed by a Design Change Package (DCP) (CF3.ID9, Ref. 1.26). A DCP is required for a design change that meets one or more of the following conditions: (1) a Licensing Basis Impact Evaluation (LBIE, PG&E's process that implements 50.59 safety evaluations) is required because of an affirmative response to LBIE screening questions; (2) it involves a change to the design bases of the plant; or (3) management requires a Design Change Evaluation (DCE) (a detailed interdiscipline technical evaluation) to be formally documented. The DCP provides an organized and systematic way of considering the change in the context of the design bases.

Other design change vehicles and the procedures that define their content and use include:

(a) Maintenance Modification Packages (CF3.ID8, Ref. 1.25)

(b) Maintenance Modification Action Requests (CF3.ID10, Ref. 1.27)

(c) Replacement or New Part Evaluations (CF3.ID13, Ref. 1.30)

In the following discussion, the basic content and flow of a DCP from development through implementation and closure are described. These other design change vehicles follow a generally similar path, but use only portions of the DCP process, appropriate to the changes they are implementing. Scope and screening requirements provide assurance that important considerations are not missed by the use of the wrong vehicle.

(4) Detailed Design and Documentation. The documentation for a design change is produced through the development and/or revision of controlled design and implementation documents (CF3, Ref. 1.19). This process is rigorously controlled to maintain the consistency of design documents and the design bases. It is also controlled to allow a complete and traceable record of the change to assist current and future evaluations of design bases and configuration. The key IDAPs and DLAPs that control design activities are a part of the Quality Assurance Program and comply with ANSI N45.2.11-1974 requirements, and are listed below. Other procedures that may be required depending on the nature of the change are also included below. This list is necessarily long because of the complex nature and the many requirements that apply to nuclear power plant design and licensing. Procedure CF3.ID9 (Ref. 1.26) provides the user with guidance, checklists, and forms for the proper implementation of these activities.

(a) Design Criteria Memoranda (CF3.ID2, Ref. 1.20). This procedure requires careful review and documentation of the design bases. If changes are required, the procedure controls them to ensure that the revisions are available and acceptable to the parties affected, and that it is properly documented upon completion of the associated physical work.

(b) Specifications (CF3.ID16, Ref. 1.32). This procedure requires development of technical requirements to ensure associated equipment and services meet the design bases. Checks are built into this process and the procurement process to ensure proper understanding and conformance with the design bases and requirements described in the specification.

(c) Design Calculations (CF3.ID4, Ref. 1.22). This procedure requires identification, revision or creation, coordination, and approval of relevant calculations in a controlled manner that ensures design basis margins are maintained as required and are available to affected personnel at the various stages of the DCP.

(d) Drawing Preparation and Approval (CF3.ID5, Ref. 1.23). This provides for identification and development of detailed revisions to existing drawings and/or development of new drawings in a controlled manner, with the appropriate approvals, and updating of the permanent plant records upon completion of the associated physical work.

(e) Setpoint Change Control Program (CF6.ID2, Ref. 1.43). This procedure provides a graded program with more rigorous requirements for the most important setpoints. It requires identification of setpoint changes resulting from a DCP (or other change vehicle) and revision by appropriate organizations, and coordinated review by the affected organizations, including Operations, Westinghouse, analysis groups, and instrumentation and control groups. Through this review and coordination process, consistency between the design bases and implementation is maintained.

(f) Classification of Structures, Systems, and Components (CF3.NE1, Ref. 1.112). This procedure defines the codes, standards, regulatory guides, and commitments that govern the classification of structures, systems, and components (SSCs) for DCPP. These classifications reflect the design bases of the plant, and determine the requirements and procedures to be applied during design, fabrication, installation, testing, operation, maintenance, and parts-replacement activities to ensure that the design bases are maintained.

(g) Design Documents Prepared by External Contractors (CF3.ID17, Ref. 1.33). This provides for the proper and controlled communication of the design bases, design requirements, and information between PG&E and external contractors. This also provides controls for the review and acceptance of external contractor work.

(h) Coordination of Safety-Related Analytical Work Performed by Vendors (TS3.ID1, Ref. 1.73). This procedure provides for the proper and controlled communication of the design bases, design requirements, and information between PG&E and external contractors doing safety-related

analytical work that supports or impacts DCPP activities. It also ensures that the resulting analysis information is reviewed and disseminated to appropriate departments to ensure maintaining the design bases.

(i) Environmental Qualification (EQ) Program (CF3.ID3, Ref. 1.21). This procedure provides for the development and implementation of the requirements of 10 CFR 50.49. The equipment within the scope of the EQ Program is electrical equipment located in harsh environments that is relied upon to perform required post-accident safety functions as delineated in 10 CFR 50.49.

(j) Design Change Package Development (CF3.ID9, Ref. 1.26). As noted above, this procedure is the overall procedure that provides for the development and coordination of design changes. A portion of this procedure provides the requirements and process for performing independent design verification of the design changes to ensure that the design meets specified design inputs and design bases.

It also provides direction and requirements for performing a Seismically Induced Systems Interaction Program (SISIP) evaluation. The SISIP evaluation provides assurance that no SSC required to perform its design basis functions will be adversely affected by another system, structure, or component in a seismic event.

(k) Seismic Configuration Control Program (CF3.ID11, Ref. 1.28). This procedure establishes the requirements for the graded quality program for seismic configuration control of certain existing Design Class II and III[3] structures, systems, and components that have seismic qualification requirements. The Seismic Configuration Control Program (SCCP) defined by this procedure provides measures to identify SCCP equipment to ensure that NPG personnel are aware of their seismic qualification requirements and do not invalidate such qualifications through engineering, construction, maintenance, or procurement activities. Equipment within the scope of this program must be seismically qualified to satisfy license or FSAR Update commitments or to ensure the functionality of Design Class I components.

(l) Processing of Information Provided by Suppliers (CF7.ID3, Ref. 1.121). This procedure provides the guidance and methods to be used to ensure that supplier-provided information associated with existing or future plant equipment is processed in an efficient and consistent manner. This

[3] PG&E Design Classes II and III do not correspond to ASME Code Classes 2 and 3 classification. DCPP piping systems are committed to meet USAS B31.1 Code and other Code requirements. This commitment preceded the development of ASME Section III, which identifies and uses ASME Code Class designations.

procedure provides a method for screening and transmitting that information to the appropriate individuals for disposition to ensure control of the configuration and design bases of the plant.

(m) Graded Quality Program for Regulatory Guide (RG) 1.97 Category 2 and 3 Instrumentation (CF3.ID12, Ref. 1.29). This procedure establishes the quality and configuration control requirements for certain RG 1.97 post-accident monitoring instrumentation that must meet its design bases, but is not required to meet 10 CFR 50 Appendix B quality assurance requirements. RG 1.97 adopts a graded approach to design, qualification, and quality requirements depending upon the importance to safety of the measurement of a specific variable. This procedure applies to the instruments with less stringent requirements.

(n) Licensing Basis Impact Evaluations (LBIE) (TS3.ID2, Ref. 1.74). This procedure establishes the requirements of and controls the processes for evaluating the impact on the licensing basis of changes to various activities associated with the design and operation of the plant. It also determines whether prior regulatory agency approval is required before implementing activities or conducting tests or experiments that will result in changes to the facility, its procedures, or licensing basis documents.

(o) Technical Specification Change Process (XI3.ID1, Ref. 1.78). This procedure provides direction and controls for processing license amendment requests for proposed changes to the DCPP Technical Specifications. This process ensures regulatory approval is received prior to undertaking these related activities.

(p) Post-Modification Testing (AD13.ID2, Ref. 1.86). This procedure establishes the administrative controls to ensure that adequate Post-Modification Testing (PMT) is identified and conducted following a plant modification to verify the capability of the equipment affected to meet the functional requirements of the related design bases.

(q) Component Database Program - Change Process (CF2.ID7, Ref. 1.18). This procedure describes the requirements for initiating, processing, implementing, and tracking changes made to the PIMS Component Database (CDB) records, which include technical and design data, design and field setpoints, and manufacturing data. This process has a security system that ensures that the CDB data continues to reflect the physical configuration of the plant, its operating procedures and the current design bases of the associated systems, structures, and components. Some of the functions of the CDB are to provide current information to control and direct activities such as clearances, work orders, and material control.

(r) Field Correction Transmittal Processing (CF3.ID6, Ref. 1.24). This procedure establishes the process and controls for maintaining the configuration of the plant through an as-built process. This process is provided to ensure incorporation of information that is within approved design bases into the various design documents.

(S) DCPP Final Safety Analysis Report (FSAR) Update Revision and Maintenance (XI3.ID2, Ref. 1.79). This procedure provides the administrative controls necessary to revise and maintain the DCPP FSAR Update current and reflective of the design and licensing bases. Controls are included for the initiation, processing, and implementation of changes to the FSAR Update, filing with the NRC, and controlled distribution of revisions to meet the requirements of 10 CFR 50.71(e).

(T) Development and Independent Verification of Calculations or Computer Programs (CF3.ID15, Ref. 1.31). This procedure establishes the requirements for the development and verification of technical calculations, computer programs, and subsequent revisions that are themselves part of, or which are bases for, testing, analysis, calibration, operating, maintenance, and other procedures that are important to safety or important to environmental quality. This procedure does not cover computer system software or design calculations covered by "Design Calculations" (CF3.ID4, Ref. 1.22).

(5) Design Change Package Development. Design Change Packages (DCPs) are developed to assemble the design change information described above in an integrated package to facilitate review and communication to the sections of the organization affected (CF3.ID9, Ref. 1.26). This process requires a review for technical and licensing impacts, including those that affect multiple parts of the organization. This review is guided by discussion, requirements, and checklists within the design change procedures, as well as discussion and requirements within the related procedures and documents.

(6) Design Change Package Distribution Coordination. Draft DCPs are distributed for review to the NPG organizations affected (Advance DCP Review) prior to being finalized. This is done to check that the design change impacts are acceptable and compatible with other plant requirements and restraints (CF3.ID9, Ref. 1.26). The organizations involved in these reviews typically include Engineering, Operations, Maintenance, Materials Services, and Learning Services.

(7) Final Review. Final DCP review and approval involves LBIE screening and development of an LBIE if required in accordance with Procedure TS3.ID2

(Ref. 1.74). This also involves the performance of independent verification (CF3.ID9, Ref. 1.26).

(8) Approval. The completed DCP is forwarded to the design change coordinator to initiate formal plant acceptance for implementation in accordance with Procedure CF4.ID3 (Ref. 1.36). The Plant Staff Review Committee (PSRC) reviews DCPs that require completion of an LBIE (i.e., one or more of the LBIE screening questions answered "Yes") and others that management requests in accordance with Technical Specifications and the procedure that specifies the PSRC charter (OM4.ID2, Ref. 1.130). DCPs are approved by the plant manager or his designee.

(9) Implementation. The processing and implementation of the DCP then proceeds through the following steps:

(a) Work Planning (AD7, Ref. 1.10) - Controlled work packages that contain the necessary information to complete the activity are developed in accordance with "Use of PIMS Work Order Module" (AD7.ID1, Ref. 1.136) and follow the work through its implementation. The following are included in these packages, as needed. (Other changes in support of the DCP may be required; some are discussed under Temporary Modifications). The DCP planning and work package development process is thorough and provides for effective implementation without compromise of the design bases.

(i) Controlled procedures for performing work (AD2.ID1, Ref. 1.138)

(ii) Specific tests (AD13, Ref. 1.15)

(iii) Identified inspections (AD5, Ref. 1.9)

(iv) Scaffolding requirements (AD7.ID5, Ref. 1.137)

(v) Inservice Inspections (ISI) (AD5.ID2, Ref. 1.90)

(vi) Post-modification testing (AD13.ID2, Ref. 1.86)

(vii) Inservice Testing (IST) (AD13.ID5, Ref. 1.88)

(viii) Post-maintenance testing (AD13.ID4, Ref. 1.87)

(ix) Procurement of materials (AD9.ID1, Ref. 1.122)

(x) Control and staging of materials (CF5, Ref. 1.41)

(xi) ALARA reviews and Radiation Work Permits (RP1, Ref. 1.63)

(b) Implementation - The implementation of the work orders requires the performance of the following associated activities:

(i) Request and obtain clearances (OP2.ID1, OP2.ID2, Refs. 1.123 and 1.124)

(ii) Perform inspections (AD5.ID1, AD5.ID2, Refs. 1.125, 1.90)

(iii) Request field changes (CF4.ID4, Ref. 1.37)

(iv) Perform testing (AD13.ID2, AD13.ID4, AD13.ID5, Ref. 1.86, 1.87, 1.88)

(v) Provide training (Operations, Maintenance, etc.) (TQ2.ID4, Ref. 1.126)

(vi) Provide as-built documents to the control room, if required (CF4.ID3, Ref. 1.36)

(vii) Return equipment to service (OP1, Ref. 1.61)

(c) Configuration Updates - Documents and information system records affected that are identified and reviewed during the preparation stage are formally updated after the change has been implemented. These include:

(i) Design Documents (CF3.ID2, CF3.ID3, CF3.ID4, CF3.NE1, Refs. 1.20, 1.21, 1.22, and 1.112)

(ii) Control Room Drawings (AD3.ID2, Ref. 1.7)

(iii) Training and Simulator Updates (TQ1, TQ2; Refs. 1.67, 1.69)

(iv) PIMS Component Database Updates (CF2.ID7, Ref. 1.18)

(v) Operating, Maintenance, and Surveillance Test Procedures (AD1.ID2, AD1.ID3, Refs. 1.3 and 1.4)

(vi) FSAR Update (XI3.ID2, Ref. 1.79)

(d) Tracking - Activities associated with the design change process are tracked using PIMS as defined in Procedure OM7.ID1 (Ref. 1.56). This provides a mechanism for tracking the status and for recording the proper closure of required activities, including documentation.

(10) Document Control and Records. Document control requirements are applied to safety-related design and configuration control documentation such that revision control and traceability are maintained and current documents are available for use. Document control requirements are either specified in the individual procedures that control the specific document or in procedures associated with PD-AD3, Document Control (Ref. 1.6). Record copies of these documents are maintained on microfilm with indices to a Records Management System such that past revisions are retrievable. Records requirements are specified in the procedures associated with PD-AD10, Records (Ref. 1.13).

Temporary Modifications

A number of processes ensure that modifications of a temporary nature, often required in the performance of design changes and maintenance activities, are properly controlled. This is essential to maintaining design and configuration control. Specific procedures that control these processes include, but are not limited to:

(1) Temporary Modifications - Plant Jumpers and Measuring and Test Equipment (M&TE) (CF4.ID7, Ref. 1.38)

(2) Temporary Attachments (CF4.ID8, Ref. 1.39)

(3) Seismically Induced Systems Interaction Program (SISIP) Review of Housekeeping Activities (AD4.ID3, Ref. 1.131)

(4) Control of Doors Important to Safety (AD7.DC5, Ref. 1.113)

(5) Use and Control of Temporary Radiation Shielding (RP1.ID2, Ref. 1.65)

(6) Control of Scaffolding (AD7.ID5, Ref. 1.137)

(7) Control of Plant Floor Loading (MA1.ID7, Ref. 1.49)

(8) Control of Temporary Rigging from Plant Equipment, Piping, and Structural Members (MA1.ID8, Ref. 1.50)

(9) Rigging and Load Handling (MA1.ID11, Ref. 1.51)

(10) Plant Crane Operating Restrictions (MA1.ID14, Ref. 1.52)

External Analysis and Design Support

The previous discussion has focused on internal PG&E design and work control processes. These internal processes cover a significant part of DCPP's design, as PG&E has and continues to function as its own architect and engineer. However, PG&E has also relied on equipment vendors, other architect/engineer firms, and consultants (service providers) for specific parts of the DCPP design. In some cases, their services are still used (e.g., Westinghouse for fuel design, safety analysis and Nuclear Steam Supply System (NSSS) support). Since these activities are an integral part of the plant design, they also must conform to the design bases and require effective control. This control is provided through interfaces with the design change process and other processes as described below.

The exchange of information and requirements between these service providers and PG&E is controlled by procedures that include:

(1) Nuclear Fuel Fabrication and Analysis Services (TS2.ID1, Ref. 1.139)

(2) Processing of Information Provided by Suppliers (CF7.ID3, Ref. 1.121)

(3) Design Documents Prepared by External Contractors (CF3.ID17, Ref. 1.33)

(4) Coordination of Safety-Related Analysis Work Performed by Vendors (TS3.ID1, Ref. 1.73)

(5) Processing of Supplier Engineering Documents (CF7.ID4, Ref. 1.145)

These procedures provide assurance, through specific documented communications and reviews, that the design requirements and bases are understood by the service provider, that PG&E understands the providers' products and methodology, and that both parties have sufficient understanding of the work done to avoid compromising the design bases.

The service-provider interface and providers' products generally have been satisfactory, as shown by independent verification and review of products such as the fuel design and associated safety analysis. However, there have been some significant problems in this area in the past. One example was the design interface problem that occurred in the late 1970s and the early 1980s, which resulted in the DVP and IDVP described in the Introduction section. Substantial changes in interface control were made as a result of the QA reviews and activities in response to the IDVP. Further improvements have been made over time based on the heightened sensitivity in this area.

No significant issues have been identified in recent years, and ongoing audits and reviews show generally satisfactory performance. Any problems identified have been handled through the normal problem identification and resolution process, which is described in Section (d), Processes for Problem Identification and Resolution. This supports the conclusion that the current DCPP processes provide adequate monitoring and control of service provider interfaces and products. Low level problems do surface periodically, indicating that continued vigilance in this area is needed, particularly as expectations for more rigorous adherence to design details continue to increase.

Vendor Manual Program

In addition to plant analysis and design details developed by PG&E and its providers, the plant design relies on the performance of vendor-supplied equipment. This equipment was provided by the vendors to meet the requirements of PG&E and/or Westinghouse specifications, which provided the vendor with design requirements. The vendor provided equipment to meet those requirements and provided certifications and/or test results to demonstrate compliance. To continue to provide the intended functionality, the equipment must be operated and maintained in accordance with the vendor's requirements. PG&E design details, as well as operating and maintenance procedures, were originally based on vendor information.

As the vendors continue to develop and sell new products, additional experience may result in changes and improvements to their products, manuals, recommendations, and limitations. Major vendors like Westinghouse have formal programs to alert customers to these changes and to provide upgrades to previously purchased and installed equipment when needed.

In 1990, PG&E assembled available information and worked with vendors of key equipment to determine if their manuals were up to date, or if there was new information that should be included in the manuals to support maintenance and/or operating procedures. About 200 key vendor manuals were upgraded to incorporate current information and recommendations, during a program that lasted several years. Procedure CF7.ID1 (Ref. 1.45) now controls these manuals.

Procedure Change Control Process

PG&E's process for the development and revision of procedures is designed to ensure that changes are reviewed specifically for their impact on the design and licensing bases. This process is defined in Program Directive AD1 (Ref. 1.1), Administrative Controls Program, and its associated IDAPs and DLAPs.

The procedure control process was established as part of the Quality Assurance program described in the FSAR Update, (Ref. 3.2) Chapter 17. This process was developed to meet the requirements of RG 1.33, Revision 2, February 1978; ANSI N18.7/ANS 3.2-1976 and DCPP's Technical Specifications. (Ref. 3.3)

The specific attributes associated with the procedure change control process (AD1.ID1, Ref. 1.2) that are relevant to maintaining design and configuration control include:

(1) Procedure sponsors are required (AD1.ID1, AD1.DC1; Refs. 1.2, 1.127) to ensure that the procedure and changes conform to applicable technical criteria and company and regulatory requirements, such as:

- (a) Applicable vendor manuals
- (b) Approved PG&E design documents
- (c) Commitments in the Procedure Commitment Database[4]
- (d) NRC regulations
- (e) Design Criteria Memoranda

[4] The Procedure Commitment Database (PCD) contains recurring regulatory commitments as well as commitments generated internally by PG&E, such as Nonconformance Report (NCR) corrective actions and recommendations from industry operating experience. The majority of design basis requirements are not contained in the PCD; they are found in DCMs and associated documents.

(f) Final Safety Analysis Report Update

(g) Safety Evaluation Reports

(h) Supplemental Safety Evaluation Reports

(i) Technical Specifications

(2) In addition, the procedure sponsor is required (AD1.ID1, AD1.DC1; Refs. 1.2, 1.127) to ensure that the procedure will work and that it is technically correct. Ensuring the technical correctness includes, but is not limited to, confirmation that:

(a) Calculations performed are correct

(b) Scaling calculations that support values in procedures are reviewed and/or verified

(c) Setpoints are correctly specified

(d) The procedure is consistent with the license, including whether 10 CFR 50.59 applies

(e) Technical specifications, cautionary notes, and other such references are specified clearly

(f) Valve lineups, valve numbers, switches, breakers, limits, acceptance criteria, and other similar information are correct

(3) Licensing Basis Impact Evaluation (LBIE) screening questions (AD1.ID2, AD1.ID3; Refs. 1.3, 1.4) are specifically included in the review process to determine if there is:

(a) A change to the Operating License and attachments

(b) A change to a commitment in the Procedure Commitment Database (PCD)

(c) A change that would require a 10 CFR 50.59 safety evaluation

(d) A change that would impact the Environmental Protection Plan implementation

(e) A change that would impact Security Plan implementation

(f) A change that would impact Emergency Plan implementation

(g) A change to the FSAR

If the answer to any of the screening questions is “Yes” then the sponsor is required to document the formal LBIE screen and perform a full LBIE, as

appropriate, in accordance with Procedure TS3.ID2 (Ref. 1.74). This process is discussed in more detail in the 10 CFR 50.59 subsection below.

(4) The PSRC reviews many new or revised safety-related procedures[5] and recommends them for approval. These procedures are then approved by the plant manager, prior to implementation (AD1.ID2, Ref. 1.3).

(5) On-the-Spot Changes (OTSCs) to procedures are allowed, provided that the intent of the original procedure is not altered. OTSCs are temporary changes to procedures that can be implemented, after approval, on a temporary basis while final revision, review, and approval of the procedure are being obtained. This process is controlled by Procedure AD1.ID7 (Ref. 1.5). The change must be approved by two management staff members who meet the applicable qualification requirements of ANS 3.1-1978, and are knowledgeable in the subject area of the procedure. For changes to certain types of procedures, at least one approver must also hold a Senior Reactor Operator (SRO) license. For the OTSC process to be used, all LBIE screening questions must result in "No" answers and the change cannot modify or delete a commitment in the Procedure Commitment Database.

Processes that Implement 10 CFR 50.59 Reviews

PG&E implements the reviews required by 10 CFR 50.59 as part of the LBIE process. This process is defined in Procedure TS3.ID2 (Ref. 1.74). The LBIE process addresses the major documents and programs that constitute the Diablo Canyon Power Plant's licensing bases, including the Final Safety Analysis Report (FSAR) Update, the Fire Protection Program, the Quality Assurance Program, the Environmental Protection Plan, the Emergency Plan, and the Security Plan. One part of the LBIE process involves performing 10 CFR 50.59 safety evaluations for effects of DCPP activities on the licensing bases as described in the FSAR Update. Separate evaluations are made for environmental, emergency, and security issues, if necessary.

Although the term LBIE was defined in 1993 to better reflect that evaluations were done for various facets of the licensing bases, 10 CFR 50.59 safety evaluations have been performed in accordance with NPG-written procedures since DCPP received an operating license.

The current LBIE process provides a systematic and consistent method of performing evaluations of changes being made to the plant facilities and procedures. The intent of this process is to prevent changes to the configuration of the plant, procedures, or methods of operation that may

[5] A recently approved license amendment (Ref. 3.39) reduces the PSRC review requirement to focus on key procedures. This change has not yet been fully implemented.

have an adverse effect on safety from occurring without required reviews and prior regulatory approval. The application of this process serves to verify that the plant continues to be operated and maintained in a manner that is consistent with the design and licensing bases.

The LBIE process, as described in IDAP TS3.ID2, is divided into three parts:

(1) Screening to determine the need for prior regulatory approval

(2) Screening to determine the need for a specific evaluation (LBIE screening); there is a separate section for each of licensing basis programs being screened

(3) Performance of the required evaluations (LBIE)

The procedures that govern various activities that can change plant configuration and/or plant procedures contain steps that require that the LBIE process be followed. In some cases, such as for the Procedure Control Process, the LBIE screening questions are integrated into the specific activity procedure, while for other activities, the LBIE procedure (TS3.ID2, Ref. 1.74) is referenced for use. Activities to which the LBIE process is applied and their associated procedures include:

(1) FSAR Update changes (XI3.ID2 , Ref. 1.79)

(2) Procedures, procedure revisions and rescissions (AD1.ID2, 3, 7, Refs. 1.3, 1.4, and 1.5)

(3) Equipment Control Guidelines (ECGs) and changes (see Appendix C for definition of ECG) (OP1.DC16, Ref. 1.114)

(4) Design changes (CF3.ID8, 9, 10, Refs. 1.25, 1.26, and 1.27)

(5) DCMs and their changes (CF3.ID2, Ref. 1.20)

(6) Setpoint changes (CF6.ID2, Ref. 1.43)

(7) Temporary Modification Control, Plant Jumpers and M&TE (CF4.ID7, Ref. 1.38)

(8) Temporary Shielding Requests (RP1.ID2 , Ref. 1.65)

(9) Event Investigation/Response Teams (OM7.ID3, Ref. 1.57)

(10) Fire Hazards Appendix R Evaluations (FHAREs) (Engineering, Mechanical Implementing Procedure M-1, Ref. 1.115)

(11) Commitment changes (XI4.ID2, Ref. 1.81)

(12) Q-List changes (Q-List, Ref. 5.65)

The LBIE process contains a question as to whether the activity causes a change to the Technical Specifications. If the activity causes a change to the Technical Specifications, submittal of a license amendment request to the NRC is required.

The current LBIE screen questions (Ref. 1.74) that are associated with determining the need for a 10 CFR 50.59 safety evaluation are stated in the LBIE procedure (TS3.ID2, Ref. 1.74) as follows:

> *"SECTION 1. <u>10 CFR 50.59, 10 CFR 50.54(a)(3), and OL Condition 2.C.(5)b./2.C.(4)b. Screen</u>*
>
> *a) Does it involve a change to the facility design, function or method of performing the function as described in the SAR, including text, tables, and figures and including the Fire Protection Program (FSAR Update, Section 9.5) and Quality Assurance Program (FSAR Update, Chapter 17)? (See Appendix 7.5 of Ref. 1.74)*
>
> *b) Does it involve a change to procedures, system operation or administrative control over plant activities as described in the SAR, including procedures related to the Fire Protection Program (FSAR Update, Section 9.5) and the Quality Assurance Program (FSAR Update, Chapter 17)?*
>
> *c) Does it result in a test, experiment, condition or configuration that might affect safe operation of the plant but was not anticipated, described or evaluated in the SAR?"*

If any of the 10 CFR 50.59 screen questions is answered "Yes," a 10 CFR 50.59 safety evaluation must be completed.

The 10 CFR 50.59 Safety Evaluation in the LBIE procedure contains nine questions. The first seven questions are directly derived from the three 10 CFR 50.59(a)(2 criteria involving an unreviewed safety question (USQ), and follow the guidance of NSAC-125[6] (Ref. 5.23). If any of these seven questions is answered "Yes," then the proposed activity involves a USQ and NRC approval is required prior to implementing the activity.

The remaining two questions of this portion of the LBIE involve the Fire Protection Plan (FPP) and the QA Program. If the proposed activity involves a change to either of these programs, further evaluation is required. The questions concerning the FPP and the QA Program were

[6] PG&E recognizes that the NRC is continuing to evaluate NSAC-125 and its compatibility with the 10 CFR 50.59 regulations. In the interim, PG&E has provided guidance to LBIE preparers reflecting the NRC's position.

added to this section of the LBIE because these programs are contained in the FSAR Update and a consolidated evaluation of FSAR Update programs was deemed effective.

Completed LBIEs are presented to the PSRC for discussion, review, and recommendation regarding approval. The plant manager then approves the LBIE before the proposed activity can be implemented. The Nuclear Safety Oversight Committee (NSOC) also is responsible for reviewing the 50.59 Safety Evaluation section of LBIEs to verify that the USQ determination was correctly performed. A summary report of 10 CFR 50.59 evaluations is periodically submitted to the NRC.

Processes that Implement 10 CFR 50.71(e) FSAR Updates

PG&E's process for controlling the FSAR Update is designed to ensure that the document is maintained up to date and consistent with current design, physical configuration, analyses, and operation of the facility. The current FSAR Update process is controlled procedurally by XI3.ID2, "DCPP FSAR Update Revision and Maintenance" (Ref. 1.79).

The format and content of the FSAR Update comply with Revision 1 of Regulatory Guide 1.70. PG&E's commitment to this regulatory guide establishes the primary elements of the licensing bases.

The FSAR Update process complies with 10 CFR 50.71(e). Consistent with these requirements, PG&E files a revision to the FSAR Update applicable to DCPP Units 1 and 2 within six months following completion of each Unit 2 refueling outage, with the interval between revisions not to exceed 24 months. As specified in 10 CFR 50.71(e) , the revision to the FSAR Update includes the effects of:

(1) All changes, permanent or temporary, made in the plant or plant procedures as described in the FSAR Update

(2) All safety evaluations performed by PG&E since the previous revision to the update, either in support of issued license amendments or in support of the conclusion that the change did not involve an unreviewed safety question

(3) All analyses of new safety issues performed by or on behalf of PG&E at the NRC's request since the last revision to the update

The FSAR Update process (Ref. 1.79) specifies that individuals have the responsibility to initiate an FSAR Update Change Request if they are aware of any of the above items that would require a change to the information presented in the FSAR Update or if they are aware of an apparent

deviation from the information presented in the FSAR Update that is discovered in the plant, procedures, or associated documentation.

The origin of FSAR Update Change Requests has direct ties to the following processes:

(1) The Design Control Process (CF3.ID9, Ref. 1.26; CF4.ID3, Ref. 1.36)

(2) The Procedure Control Process (AD1, Ref. 1.1)

(3) The LBIE Process (TS3.ID2, Ref. 1.74)

(4) License Amendments/Technical Specifications Change Process (XI3.ID1, Ref. 1.78)

(5) Coordination of Safety-Related Analytical Work Performed by Vendors (TS3.ID1, Ref. 1.73)

The documentation that is developed as a part of these processes typically serves as the basis for the FSAR Update changes.

In addition to individual items that are identified as part of the above-noted change processes, the FSAR Update process assigns organizational ownership for each FSAR section and specifies that reviews be performed on a scheduled basis to identify inconsistencies and needed changes. These FSAR section owners also are responsible for reviewing the requested changes submitted by others. This provides a secondary means of identifying and validating necessary changes.

The FSAR is available to the DCPP organization in two formats: (1) controlled hardcopies, and (2) an electronic version. The electronic version shows pending FSAR changes developed since the last formal revision submitted to the NRC.

Processes that Implement 10 CFR 50, Appendix B

The Quality Assurance (QA) program at DCPP implements the requirements of 10 CFR 50, Appendix B for the safety-related aspects of design, procurement, modification, operation, maintenance, and support activities associated with DCPP. Elements of the QA program also are applied to nonsafety-related items and activities based on their potential to affect safe and reliable plant operation.

The QA program is described in Chapter 17 of the FSAR Update, and is implemented in many DCPP procedures. The QA program is defined in OM5 (Ref. 1.54). This program has been established in accordance with the requirements of 10 CFR 50, Appendix B. While the processes that implement the QA Program have evolved with organizational changes over the years and the program itself has been enhanced, procedures have been in place to ensure compliance with the

requirements of 10 CFR 50, Appendix B, since the regulation was promulgated in 1970. Table 1 identifies the PG&E Program Directives that implement the QA program. Specifically, this table identifies the 18 criteria associated with 10 CFR 50, Appendix B, and identifies the Program Directives that implement each criterion. This table is maintained as part of Procedure OM5 (Ref. 1.54).

The majority of the processes that implement the QA program, particularly those that relate to design and procedure control, were described in the earlier part of this subsection. The processes that implement corrective actions and audits are described in Section (d), Processes for Problem Identification and Resolution.

TABLE 1

MATRIX OF 10 CFR 50, APPENDIX B CRITERIA AND PROGRAM DIRECTIVES

	Program Directives / CRITERIA	AD1	AD2	AD3	AD4	AD5	AD7	AD9	AD10	AD13	CF1	CF2	CF3	CF4	CF5	CF6	MA1	MA2	MA3	OM1	OM4	OM5	OM7	OP1	OP2	TS2
I.	Organization																			■						
II.	Quality Assurance Program																					■				
III.	Design Control										■	■	■	■	■	■										
IV.	Procurement Document Control							■																		■
V.	Instructions, Procedures and Drawings	■	■				■																			
VI.	Document Control			■																						
VII.	Control of Purchased Material				■			■							■											■
VIII.	Identification and Control of Materials, Parts and Components										■				■										■	
IX.	Special Processes																		■							
X.	Inspection					■																				
XI.	Test Control									■																
XII.	Control of Measuring and Test Equipment																	■								
XIII.	Handling, Storage, and Shipping														■											
XIV.	Inspection, Test and Operating Status					■				■	■						■						■	■	■	
XV.	Nonconforming Materials, Parts or Components																						■			
XVI.	Corrective Action																						■			
XVII.	Quality Assurance Records								■																	
XVIII.	Audits																				■					

Other Potential Impacts to the Design Bases

In addition to the key change processes described above, it is important to note how PG&E controls the more subtle forms of changes in a manner that maintains consistency with the design bases. Some examples of the more subtle forms of changes and the controls that PG&E employs to prevent any adverse impacts are described here.

(1) Operator Work Arounds

Operator work arounds are activities required to compensate for design or maintenance problems (e.g., operation with control rods in manual instead of automatic due to equipment problems). Operator work arounds are tracked by the Operations director, who maintains a list of them on the plant's electronic bulletin board for viewing by plant personnel. PG&E's policy is to limit the number of work arounds by aggressive tracking, review and resolution by Engineering and/or Maintenance.

(2) Technical Specification Interpretations

Technical Specification interpretations have been used in the past to clarify requirements that could be fulfilled in different ways. These interpretations are reviewed by the PSRC and approved by the Plant Manager in accordance with Procedure XI3.ID3 (Ref. 1.143). Additionally, existing Technical Specification interpretations were reviewed recently for consistency with design and licensing bases and PG&E believes that current interpretations comply with the license.

(3) Shift and Standing Orders

Shift and standing orders provide written guidance describing an operational problem, and direct that certain operator actions be taken. Procedure OP1.DC31 (Ref. 1.144) requires that these orders be written by senior Operations management, with the involvement of applicable engineering personnel when required, to carefully control possible conflicts with the design bases. This procedure clearly specifies that such information shall not be used in lieu of approved procedures and shall not contradict approved procedures or regulatory requirements.

(4) Use of "Not Applicable" (N/A) for Steps in a Procedure

Use of N/A could lead to compromise of the design bases, if, for example, a step in the procedure is designed to ensure isolation of a redundant component before testing. On the other hand, use of N/A for procedure steps has been used for years

as a means to select only the applicable parts of a test that cover many aspects of a system or component. The use of N/A for procedures is controlled by AD2.ID1 (Ref. 1.138). Use of N/A is only allowed under the following circumstances: (1) steps that are specifically indicated as not being always required; and (2) actions or conditions called for already exist, or plant/equipment conditions are such that the step clearly does not apply, and the reason for the N/A and unexpected actions or conditions are evaluated by the shift foreman.

(5) Formal Communications

Formal communications consist of written instructions that may be used to coordinate the use of multiple procedures, other work documents, or to direct simple operations evolutions for which no procedure exists. Formal communications must be approved by the shift foreman, who holds an SRO license. Formal communications may not be used in lieu of procedures, or in situations of such complexity or safety significance that an approved plant procedure is required. The Operations senior engineer periodically reviews the formal communication log to determine the need for a procedure. Formal communications are controlled in accordance with Procedure OP1.DC12 (Ref. 1.128).

PG&E is aware that these activities could, if not properly controlled, lead to inadvertent design basis changes. These activities have, therefore, been addressed in procedures and require the appropriate level of supervision and management control. PG&E also relies on qualified, knowledgeable individuals to be aware of configuration control requirements in avoiding other inadvertent changes to the design bases.

Training

Knowledgeable, well-qualified personnel are required to implement even the best processes for maintaining and operating the plant in a manner that maintains design and configuration control. PG&E has provided significant training in many areas related to design bases and configuration management to improve awareness of the design bases and to qualify personnel who are involved with design bases.

Engineering personnel who are involved in the design and configuration control processes are trained in accordance with the Engineering Support Personnel (ESP) Training Program (TQ2.ID10, Ref. 1.140), which is accredited by the National Academy for Nuclear Training. This training program consists of orientation, position-specific, and continuing training.

ESP orientation training is a nine-week course that covers nuclear power plant administration, fundamentals, systems and operations. This course contains the following content that is applicable to design and configuration control:

(1) Administration - Provides the knowledge necessary to locate and retrieve applicable documents at DCPP. (This includes a lesson on configuration management and the supporting procedures that the engineers need to use.)

(2) Fundamentals - Provides the fundamental knowledge necessary to understand how technical concepts are applied in nuclear power plants

(3) Systems - Provides the knowledge necessary to understand the (a) design bases of plant systems and (b) component function and operation and the interrelationship between the two

(4) Operations - Utilizes a combination of classroom, simulator and in-plant walkthroughs to observe integrated plant operation; improves the knowledge of equipment operation; develops an understanding of transients, accident sequences, and plant response; and instills a respect for reactor safety and the reactor core

ESP Position-Specific Training consists of completing specific knowledge and task requirements as specified in Qualification Guides for the following engineering positions:

(1) Nuclear Technical Services Engineer

(2) Reactor Engineer

(3) Inservice Inspection Engineer

(4) Nuclear Safety Engineer

(5) Licensing Basis Management Engineer

(6) Procurement Design Engineer

(7) Quality Assurance Assessment Personnel

(8) Regulatory Services Engineer

Task qualification, including on-the-job training, is completed prior to independently performing, directly supervising, or performing a final comprehensive review of the associated task.

ESP Continuing Training is designed to keep Engineering support personnel current with respect to plant modifications, procedure changes, industry and operating experience, and technical advances associated with their job functions. Subjects addressed have included, but are not limited to, the following:

(1) License Basis Impact Evaluation
(2) Design Criteria Memoranda
(3) Environmental Qualification
(4) Station Blackout
(5) FSAR Chapter 15 - Accident Analyses
(6) FSAR Chapter 8 - Electric Power
(7) Design Change Sponsorship
(8) Temporary Modifications
(9) Probabilistic Risk Assessment
(10) Plant Clearances
(11) Maintenance Rule
(12) Plant Aging Management
(13) Offsite Power Nonconformance and Actions
(14) Ten-year Inservice Testing Program
(15) Component Database
(16) License and Design Bases
(17) Prompt Operability Assessments
(18) Design Changes
(19) Industry Events
(20) Procedure Changes

Collectively, this ESP training provides sufficient information to personnel so that they are aware of and know how to maintain the design bases.

Personnel who prepare and review safety-related procedures are qualified through procedure qualification training and safety evaluation training in accordance with TQ1.ID10 (Ref. 1.68). This includes Engineering, Operations, and Maintenance personnel.

Overall Effectiveness of Change Processes

Design Change Process Internal Assessments

PG&E's internal Quality Assurance audits have examined extensively the effectiveness and the results of the design change processes. From 1989 to the present, these examinations have primarily included the performance of "vertical-slice" Safety System Functional Audit and Reviews (SSFARs) and Safety System Outage Modification Inspections (SSOMIs). PG&E's SSFAR and SSOMI programs are discussed in more detail in Section (d), Processes for Problem Identification and Resolution. Since 1988, five SSFARs and 13 SSOMIs have been performed. The results of these audits have demonstrated a continually improving trend relative to the implementation of design changes and have determined that these processes currently are programmatically sound.

One of the early SSOMIs (Ref. 2.6) identified the need for improvement in the areas of the interface between the departments involved in design changes, design reviews and verification, design change installation, and turnover to operations. Subsequent SSOMIs (Refs. 2.12 and 2.17) recognized that corrective actions and recommendations from previous SSOMIs had led to noticeable improvements in the implementation of the design change process. The results of a more recent SSOMI (Ref. 2.25) assessment have shown a continuing improvement in the clarity, completeness, and quality of design change packages developed by Engineering. Specific improvements noted by the SSOMI teams include the level of detail addressed in the safety evaluations, the extent of documentation of engineering judgment, and the documentation of the design change technical evaluations. Also, the high level of technical knowledge of Engineering personnel has been repeatedly recognized by the SSOMI teams. Occasionally, a SSOMI team has identified issues during the design phase of the assessment that have resulted in the delay of the design change to a subsequent outage. Such was the case with the Boron Injection Tank Removal design change and the changeout of the 4-kV safety-related breakers. For the most part, however, corrective actions taken to address the SSOMI teams' findings, comments, and concerns have been successful in enabling the implementation of the design change to proceed as scheduled.

In addition to QA audits, several self-assessments have examined the design change process. The 1992 to 1993 DCPIP carefully examined existing processes, benchmarked other organizations, and surveyed users. While the primary purpose of the DCPIP was not to assess the adequacy of the design change process, it did examine the processes closely and concluded, "The existing design change process at DCPP was found to be effective, but not as efficient as desired" (DCPIP Final Report, Ref. 4.5).

In 1994, the Unit 1 sixth refueling outage "installation" SSOMI (Ref. 2.27) focused on the use of the new (introduced in late 1993) minor modification design change vehicle (AT-MM AR) and identified concerns about how it was being used and the potential reduction in involvement by

organizations potentially impacted by operational and maintenance considerations. Corrective actions were identified and implemented for these findings.

The March 28, 1996, Engineering Self-Assessment (Ref. 2.40) examined work performed in 1995 and identified a number of problems in the areas of procedural adherence, scope control, and configuration management related to the AT-MM AR design change process. The self-assessment findings were consistent with the 1994 SSOMI previously mentioned (Ref. 2.27). To address these findings, the AT-MM AR procedure has been refined, a process owner to monitor AT-MM AR process health has been appointed, and training has been performed to address the issues identified in this assessment.

A subsequent QA Technical Support Outage Assessment (TSOA) performed for the Unit 2 seventh refueling outage from April to June of 1996 (Ref. 2.33), has followed up and noted significant improvement in AT-MM AR usage. This TSOA evaluated 33 AT-MM ARs for the Unit 2 seventh refueling outage, and found them to be well documented, technically sound, and in compliance with procedural requirements.

Design Change Process External Assessments

Numerous NRC inspections have assessed the design change process over the last seven years. In the 1989 to 1990 time frame, there was an inspection focus on the design change process. NRC Inspection Report 90-23 (Ref. 3.33) summarized a number of the inspections that were performed and "*noted progress in ... areas such as the system design criteria documents, the QA system audits, and the increased communication between design and system engineering*." The same inspection report noted that the inspectors would continue to emphasize the role of Engineering and the design change process in future inspections.

Subsequent NRC inspections have continued to assess the design change process on a regular basis. Inspections of design change packages and products include 91-11 (Ref. 3.5), 92-30 (Ref. 3.16), 92-31 (Ref. 3.17), 93-26 (Ref. 3.25), and 95-06 (Ref. 3.45). NRC Inspection Report 91-11 (Ref. 3.5) identified that "*Within the design change process, communication between [PG&E's] onsite and corporate design personnel appeared to be less than adequate....*" The same inspection report also indicated that "*... the design change process appeared to have an adequate procedural structure*."

Inspection Reports 92-30 and 92-31 (Refs. 3.16 and 3.17) reviewed emergency diesel generator and RHR system design change packages, respectively, and found them to be acceptable. Inspection Report 93-26 (Ref. 3.25) shows evidence of a thorough examination of the design change process, including proper consideration of 10 CFR 50.59 reviews, FSAR Update changes, testing specifications, operating and testing procedure updates, and training revisions. This same report concluded that "*The licensee had also implemented appropriate process and procedure*

control through engineering and design process control, Quality Control and Quality Assurance oversight, review, and independent verifications."

A recent Inspection Report, 96-20 (Ref. 3.46), provided a positive indication that the design change process is working well. Regarding the 4160-V system, the NRC stated that the "*current design and testing of the 4160 V vital AC power system is in conformance with the FSAR [Update] and plant [Technical Specifications]. The licensee has been proactive in identifying and correcting degraded conditions and system design deficiencies. Engineering, operations, and maintenance staffs have demonstrated the ability to coordinate efforts in the implementation of design changes and problem resolution*." The NRC also stated that "*the system engineer was very knowledgeable on both [4160 V] system requirements and component design basis*."

Inspection Reports 90-23 (Ref. 3.33), 91-11 (Ref. 3.5), and 94-03 (Ref. 3.44) have noted the effectiveness of Quality Assurance audits in evaluating the design change process and in identifying significant issues.

Design Change Process Effectiveness Summary

PG&E believes that the design change processes have been and are functioning adequately in maintaining design and configuration control. Considering that many thousands of design changes have been processed over the operating life of the plant, the number of identified problems have been relatively few. Some of these problems have been significant, but they have not rendered a system incapable of performing its intended safety function or indicated a serious programmatic deficiency. The problems that have been identified have been or are being evaluated and resolved as part of the Problem Resolution Process, which is discussed in Section (d), Processes for Problem Identification and Resolution.

Procedure Change Control Process Internal Assessments

Internal Quality Assurance audits have examined the effectiveness of the procedure change control process by evaluating the consistency of operating, maintenance, and testing procedures with design bases and by reviewing the products and results of the design change processes as part of the SSFARs and SSOMIs discussed in Section (d), Processes for Problem Identification and Resolution. These audits have generally not expressed concerns with the defined procedure change control process. They have, however, noted problems associated with implementation that have resulted in inconsistencies between operating, maintenance, and testing procedures and the design bases. Corrective actions have focused on attention to detail, training, and work prioritization. Procedure adjustments have also been made to help resolve implementation issues.

Self-assessments performed have not identified specific issues related to the procedure change control process.

Procedure Change Control Process External Assessments

NRC inspections have not typically focused on the direct examination of the procedure change control process itself, but they have routinely examined procedures for any problems that exist. Over the past five years, NRC inspections have identified a number of instances involving inconsistencies of procedures with design and licensing basis documents, lack of needed procedural guidance, and inappropriate procedural guidance. NRC Inspection Report 91-11 (Ref. 3.5) identified two Emergency Operating Procedures (EOPs) that were revised to document a changed setpoint, before a technical basis was provided. Inspection Report 96-21, (Ref. 3.24) recently identified a failure to perform a 10 CFR 50.59 review for a change to Emergency Operating Procedure E-1.3.

The number of procedure change control problems identified in NRC inspection reports have been few and have not identified serious programmatic issues. Often, the precise cause is not immediately apparent, but on occasion it has been noted to be a lack of timeliness in incorporating changes and a failure to perform required reviews. In most cases, the problems have been implementation issues and not process definition issues.

Procedure Change Control Process Effectiveness Summary

The procedure change control process has the necessary attributes to ensure that procedures remain consistent with the DCPP design and licensing bases. Although occasionally PG&E has not correctly implemented all aspects of the procedure change control process, PG&E believes that this process is fundamentally sound and that the processes for problem identification and resolution described in Section (d), Processes for Problem Identification and Resolution, identify and correct the problems that occur.

10 CFR 50.59 (LBIE) Process Internal Assessments

Internal Quality Assurance audits have examined the effectiveness of the 10 CFR 50.59 (LBIE) process as part of performing the SSFARs and SSOMIs that were previously discussed. The SSOMI results from the Unit 1 fifth refueling outage (Ref. 2.17) stated, "*specific improvements noted by the audit team included the level of detail addressed in the safety evaluations*." This has been a repeated SSOMI observation for audits of design change packages.

In the Unit 1 sixth refueling outage SSOMI, (Ref. 2.27), two Field Change notices were identified as having been used in such a manner that they resulted in a design change that was not evaluated in accordance with the requirements of 10 CFR 50.59. In the same audit, several problems were identified with the accuracy and completeness of safety evaluations performed by Westinghouse. This was an increase in the number of 10 CFR 50.59 safety evaluation issues identified compared

to prior SSOMIs. Corrective actions have been identified and implemented for these findings. Subsequent TSOAs for the Unit 1 seventh refueling outage and the Unit 2 seventh refueling outage (Refs. 2.31 and 2.33) did not find deficiencies with 10 CFR 50.59 safety evaluations, and the TSOA for the Unit 2 seventh refueling outage reviewed Field Changes and found that they were being used appropriately.

A DCPP Engineering Self-Assessment in early 1996 (Ref. 2.40) performed an in-depth review of a sample of five safety evaluations associated with design change packages and concluded that the LBIEs were technically correct and appropriate.

A Quality Assurance audit (Audit 962700005, Ref. 2.48) was performed in December 1996 to examine 10 CFR 50.59 evaluations in operations procedure revisions. This audit was requested by the Operations director as an action related to evaluating the results of NRC Inspection Report 96-21 (Ref. 3.24), which identified the failure to perform a required 10 CFR 50.59 evaluation for an Emergency Operating Procedure (EOP) E-1.3 change. The results of this audit have not identified significant issues with the defined procedure change process or its linkage to the LBIE process, but have identified instances of incorrect implementation of process requirements. The results of this audit are being further evaluated as part of an NCR (N0002003, Ref. 5.63) that has been initiated to address the EOP E-1.3 issue and as part of another NCR on the LBIE process (N0002008, Ref. 5.25).

10 CFR 50.59 (LBIE) Process External Assessments

NRC inspections continually examine the implementation of 10 CFR 50.59 requirements in design changes and operations, maintenance, and testing activities.

In the past, there have been instances where 10 CFR 50.59 evaluations have not been properly performed. Inspection Reports 93-11 (Ref. 3.47) and 93-14 (Ref. 3.48) identified a change to the post-LOCA sampling system capabilities that did not receive such an evaluation. Inspection Report 96-06 (Ref. 3.49) identified that a safety evaluation had not been performed prior to departure from core offload practices as described in the FSAR Update. As mentioned earlier, Inspection Report 96-21 (Ref. 3.24) identified a change to Emergency Operating Procedure E-1.3 without a proper 10 CFR 50.59 evaluation.

During past NRC inspections, the NRC reviewed many 10 CFR 50.59 evaluations and found them to be acceptable. NRC Inspection Report 91-11 (Ref. 3.5), which reviewed the Unit 1 fourth refueling outage Design Change Packages, concluded that the 10 CFR 50.59 evaluations performed for the modifications "*... appeared to be adequate*." In Inspection Report 93-26 (Ref. 3.25), the NRC inspector concluded, based on a review of 10 CFR 50.59 evaluations, that PG&E had performed the evaluations and that they "*... were technically correct*." Inspection Report 93-32 (Ref. 3.6) contained an extensive review of 10 CFR 50.59 evaluations prepared for design changes, and concluded that "*in general, a good program had been established with good*

engineering support of activities" and that PG&E "*produced timely and technically sound 10 CFR 50.59 reviews*." In Inspection Report 95-06 (Ref. 3.45), the NRC observed engineering activities associated with the design change for replacing safety injection Pump 2-2 and stated that the "*safety evaluations ... appeared to have appropriately addressed the complex issue*."

10 CFR 50.59 (LBIE) Process Effectiveness Summary

PG&E believes that 10 CFR 50.59 safety evaluations have, for the most part, been adequately performed in accordance with NRC regulations and NPG procedures. There have been some instances in which 10 CFR 50.59 safety evaluations have not been properly or formally performed. PG&E believes that they have been relatively few in number and have not resulted in a USQ. As a result of the recently identified instances where 10 CFR 50.59 evaluations have not been performed as required[7], as previously mentioned, PG&E has issued an NCR (N0002008, Ref. 5.25) to further evaluate this situation and identify corrective actions to resolve this weakness. PG&E already plans to perform additional training in the 10 CFR 50.59 area to raise awareness of the importance of safety evaluations. This is discussed further in the section on "Conclusions and Future Actions."

10 CFR 50.71(e) (FSAR Update) Process Internal Assessments

During 1988 and 1989, reviews of the FSAR Update were performed by Design Engineering and System Engineering to ensure compatibility with the design bases and to ensure appropriate implementation of FSAR design requirements in plant procedures. While these efforts resulted in some improvements in the quality of the FSAR Update at that time, some inaccuracies that had been in the FSAR Update since its inception in 1984 were not fully corrected (Refs. 5.1 and 5.16).

In 1996, as a result of findings at Millstone and FSAR Update inconsistencies identified in NRC Inspection Report 96-06 (Ref. 3.49), PG&E initiated an effort to find and correct inaccuracies in the DCPP FSAR Update. Many inaccuracies were found and most were corrected in Revision 11 of the FSAR Update, issued in November 1996. The remainder will be addressed in a supplemental FSAR Update in April 1997. These inaccuracies were reviewed at the time they were found and were determined not to be safety significant. Process improvements in the form of enhanced periodic training of NPG engineers, communication of management expectations regarding FSAR Update document quality, and improved procedural guidance were also developed and implemented in 1996 to address this issue.

[7] Emergency Operating Procedure E-1.3, on switchover to cold leg recirculation, was revised without adequate 10 CFR 50.59 evaluation of certain design basis timing assumptions. This problem was the subject of a Notice of Violation issued by the NRC on January 9, 1997, based on findings identified in Inspection Report 96-21 (Ref. 3.24).

As a result of a finding from the 1996 Engineering Self-Assessment (Ref. 2.40), an "FSAR Update Process Owner" was assigned to provide for better awareness of FSAR Update requirements and to monitor the health of the process.

Late in 1996, as a result of continuing emphasis on FSAR Update accuracy at a greater level of detail, PG&E initiated further reviews of the FSAR Update from an operations perspective. The initial phase of this review was completed in December 1996. The results were screened to ensure that identified discrepancies did not require near-term actions. The discrepancies were found to be minor. At this time, this review effort is approximately 50 percent complete. Approximately seven procedures and eight FSAR Update paragraphs have been identified as needing revision.

10 CFR 50.71(e) (FSAR Update) Process External Assessments

The FSAR Update has been reviewed periodically as part of NRC inspection activities. In inspection reports over the past few years, the NRC has noted that it has reviewed the FSAR Update relevant to areas inspected and has not identified discrepancies. There also were some instances where discrepancies were noted.

NRC Inspection Report 96-06 (Ref. 3.49) identified a number of instances where design information was not consistent with the FSAR Update. These included DCM information and license amendment information that had not been reflected in the FSAR Update. In Inspection Report 96-21 (Ref. 3.24), addressing the issue on Emergency Operating Procedure E-1.3, the NRC also identified discrepancies with the FSAR Update.

While the discrepancies noted have been determined to be not safety significant, PG&E believes that additional efforts in this area will be required to address any remaining inconsistencies.

10 CFR 50.71(e) (FSAR Update) Process Effectiveness Summary

PG&E recognizes that in the past certain information in the FSAR Update has not been maintained entirely current and compatible with design documents and procedures. However, PG&E believes that the safety significant design basis information in the FSAR Update has been adequately maintained. PG&E also believes that its current process for maintaining the FSAR Update is adequate.

PG&E realizes the importance of maintaining an accurate FSAR Update and is planning additional review efforts to further enhance and ensure the accuracy of information contained therein. PG&E has committed to participate in the Nuclear Energy Institute (NEI) Licensing Basis Initiative (NEI 96-05) and will use this effort, in part, to determine the extent of further reviews. Planned future efforts in this area are further discussed in the section entitled "Conclusions and Future Actions."

Summary Conclusions

Based on a review of its current design and configuration control processes, PG&E believes that they collectively contain the necessary attributes to properly maintain engineering design and configuration control. The design control processes provide for: (1) the proper recognition and evaluation of design changes to ensure that the integrity of the design bases is maintained; (2) the communication of design change impacts to operating, maintenance, testing, and other support organizations; and (3) the incorporation of the change impacts into the documentation affected. Procedure change processes require the review of the design basis and licensing basis documents for procedure changes that are made to ensure that consistency with the design and licensing bases is maintained. In addition, PG&E's processes specifically require the implementation of 10 CFR 50.59, 10 CFR 50.71(e), and 10 CFR 50, Appendix B requirements.

PG&E recognizes that the recent issue with EOP E-1.3 has identified a need to further evaluate the LBIE process, and is committed to take appropriate corrective actions. PG&E is also committed to a further review of the FSAR Update to identify remaining inaccuracies. PG&E is confident that these actions will result in further improvements to existing documents and processes.

Based on examination of internal QA audits and assessments and NRC inspection reports, PG&E believes that its processes are being implemented in an acceptable manner to maintain design and configuration control. Some implementation problems have been found and it is expected that some problems will be identified in the future. PG&E has and will continue to evaluate problems that occur and take corrective actions to resolve the specific problems and to strengthen the processes. Overall, PG&E believes that its processes have been and continue to be effective in maintaining design and configuration control.

(b) DESIGN BASIS TRANSLATION TO OPERATING, MAINTENANCE AND TESTING PROCEDURES

This section provides PG&E's response to the following NRC request:

> *(b) Rationale for concluding that design bases requirements are translated into operating, maintenance, and testing procedures*

Introduction

PG&E believes that design basis requirements have been properly translated into the appropriate plant operating, maintenance, and testing procedures. This belief is based upon the following factors:

(1) The procedures were originally developed by experienced PG&E personnel who had operated Humboldt Bay nuclear plant and had interacted with Engineering and the NSSS supplier during the initial DCPP design, providing good consistency with the design bases.

(2) Technical Specifications and Equipment Control Guidelines (ECGs) reflect the design bases, have been thoroughly reviewed against the bases, are used as a primary input to operational activities, and are well-understood by Operations personnel.

(3) The change control processes contain the necessary attributes to maintain the consistency between procedures and design basis requirements.

(4) The Design Criteria Memoranda (DCM) enhancement and Setpoint programs have reviewed operating, maintenance, and testing procedure consistency with the appropriate design basis information.

(5) Extensive audits and assessments of operating, maintenance and testing activities have been performed, and confirm that the processes have been generally effective in maintaining consistency between procedures and design bases.

The following topics are discussed to support the rationale that design basis requirements have been properly translated into procedures:

(1) The original operating, maintenance and testing procedure development process

(2) Technical Specifications and ECGs

(3) Review of procedures against the design bases

(4) Procedure change control processes

(5) Training

(6) Overall effectiveness of design basis translation

Original Procedure Development

This subsection describes the original development of procedures for operations, surveillance testing, and maintenance[8]. Personnel experienced with the operation of the Humboldt Bay nuclear plant were trained with design engineering personnel and interacted with Engineering and the NSSS supplier during initial DCPP design. They used the existing design basis information in procedure preparation. This information included design documents such as electrical schematics and piping schematics, Preliminary Safety Analysis Report (PSAR), Final Safety Analysis Report (FSAR), vendor manuals, a setpoint study supplied by Engineering, and equipment acceptance tests. In short, a significant effort was made to ensure that the original procedures adequately reflected the design basis information.

The development of each of these specific types of procedures is discussed below.

(1) Development of Operating Procedures:

Key plant personnel became familiar with the design basis very early in the design of Diablo Canyon by working with PG&E Engineering and Westinghouse in the writing of the PSAR sections on operations and accident analysis, as well as in the review of the entire document prior to its submittal. Senior plant personnel also participated in early design activities, including electrical and annunciator panel design. They spent an extensive amount of time in the PG&E Engineering design office (where the majority of the original plant engineering was done), and in Westinghouse's design office reviewing design documents and operating procedure guidelines and discussing accident scenarios and control room design. Plant personnel also attended a Westinghouse design school for three months, at which a variety of design topics were addressed. These individuals then wrote system descriptions for plant systems using that information and other design information from Engineering as well as data from equipment suppliers.

[8] Much of the information in this subsection is based on discussions with personnel involved in the original operating, maintenance and surveillance testing procedure development.

Key members of the original plant staff engaged in a variety of other activities to better prepare them for their roles at DCPP. For example, two senior members spent several months at the Ginna Nuclear Station assisting in the startup using Ginna's procedures. Other members of the staff were also temporarily assigned to other pressurized water reactor (PWR) plants in various stages of startup and operation. Moreover, most operations and technical personnel trained on the simulator at Zion Nuclear Station, using Zion's procedures. Building upon the experience thus gained, coupled with the aforementioned access to Engineering, Westinghouse, and other equipment suppliers, plant-specific operating procedures were prepared for DCPP. After writing the DCPP-specific operating procedures, plant personnel conducted more sessions on the Zion simulator, testing the DCPP-specific procedures. The DCPP procedures then were revised to incorporate lessons learned from the simulator experience. They also were revised, as needed, when changes were made to the design bases or accident scenarios. Finally, they were reviewed and approved by the Plant Staff Review Committee (PSRC).

For PG&E-designed systems, the plant staff used the design information provided by PG&E Engineering and documents from equipment suppliers (including NSSS information from Westinghouse) to write the operating procedures. Originally, the Engineering department did not routinely review operating procedures, but did review them for the CCW System (the most complex of the PG&E-designed safety-related systems), to ensure that the operating procedures were in accordance with the design bases.

The DCPP plant staff who prepared and/or directed the preparation of the operating procedures had Senior Operator Licenses at Humboldt Bay Power Plant, and were qualified for DCPP cold licenses. The operating procedures were also used for conducting certain integrated pre-operational and startup tests, such as the hot functional tests, to assist in validating them.

The Construction Start-Up Group also wrote pre-operational and startup test procedures using PSAR information, as well as other design documentation provided by PG&E Engineering, Westinghouse and other equipment suppliers. The startup and pre-operational test procedures were reviewed and approved by the plant staff. After performance of the startup and pre-operational tests, the results were reviewed and approved by the plant staff. This process provided an independent check that appropriate design bases were considered and demonstrated prior to systems turnover to operations. As mentioned above, these startup tests were also available as background material for the development of the operating procedures.

After the Three Mile Island (TMI) incident in 1979, PG&E participated in the Westinghouse Owners Group (WOG) efforts to address post-TMI requirements. Existing Emergency Operating Procedures (EOPs) were revised, and additional procedures were written to incorporate lessons learned from TMI, and to implement WOG emergency operating procedure guidelines and function restoration guidelines. This process incorporated plant-specific design basis information into the generic guidelines. Also, the WOG EOP bases were controlled, and were subject to PSRC review.

(2) Development of Surveillance Test Procedures:

10 CFR 50.36 specifies requirements for Technical Specifications, which include Safety Limits, Limiting Safety Systems, Limiting Conditions for Operation, Surveillance Requirements, Design Features, and Administrative Controls. The initial Technical Specifications effort resulted in "custom" specifications which were developed by qualified engineers on the plant staff working with the NSSS vendor and the PG&E Engineering department. This work was conducted in concert with the operating procedure development effort described above.

In the late 1970s, the NRC initiated efforts to shift to vendor Standard Technical Specifications (STS) as opposed to the custom specifications previously mentioned. Diablo Canyon was one of the initial plants selected for STS implementation, and extensive development and review work was conducted between the plant staff engineers, the PG&E Engineering department, the NSSS vendor, and the NRC to ensure that the DCPP specifications properly reflected the design and design bases. In some cases it was later determined that certain values in the specifications were not consistent with design basis requirements (such as in the case of emergency diesel generator fuel oil volume). However, such inconsistencies were corrected during the reviews as part of the Design Criteria Memoranda (DCM) enhancement program. The Diablo Canyon STS were reviewed by the PSRC, the PG&E Engineering department, and the NSSS vendor numerous times during the STS development.

In parallel with this STS development work, Surveillance Test Procedures (STPs) were prepared to satisfy the STS surveillance requirements and were reviewed by the PSRC. While some of the bases for these STPs were documented, there were instances where they were not, or where they were not maintained in the permanent plant records. However, such instances were corrected as part of the subsequent STP Bases reconstitution effort in the early to mid-1990s.

The Technical Specifications were included in the Design Verification Program (DVP) review, and a few changes to the Technical Specifications were required as

a result of this verification program. Technical Specifications and surveillance test procedures have been the subject of many reviews and improvements over the years, such as the Westinghouse Technical Specifications Improvement Program. Although there have been a few minor problems with the Technical Specifications and STPs, experience gained by their use, as well as numerous audits of their effectiveness, have demonstrated that they properly reflect the significant design basis information.

(3) Development of Maintenance Procedures:

Maintenance procedures were developed by the plant staff using design information provided by PG&E Engineering personnel and by the equipment suppliers (e.g., the operations and maintenance manuals) to properly incorporate design basis requirements into the maintenance procedures. Equipment suppliers were contacted as necessary for supplemental information. The procedures also implemented recommendations from various industry sources (e.g., INPO, EPRI, and NRC bulletins and information notices), and incorporated established PG&E maintenance practices.

Technical Specifications and ECGs

The Technical Specifications are one of the primary documents used by plant operations personnel in the performance of operations activities. The Technical Specifications address the key systems and components in the plant, and define their functional and performance requirements. The Technical Specifications were derived from the analyses and evaluations contained in safety analysis reports, which are in turn consistent with plant design bases. The Technical Specifications provide significant input to operational decisions, and limit system operation, configuration, and performance. Thus the extensive use of the Technical Specifications by operations provides assurance that operations procedures and activities are within the design bases.

The surveillance test requirements specified in the Technical Specifications, and the corresponding test acceptance criteria, help ensure that safety-related equipment is capable of performing its intended safety functions.

The Limiting Conditions for Operation defined in the Technical Specifications provide insight into the importance of equipment in overall plant operation, and help define the potential contribution of that equipment to plant safety risk.

In addition to the Technical Specifications, PG&E has developed and uses ECGs. The ECGs provide administrative controls and operability requirements for selected equipment not addressed

by the Technical Specifications. The ECGs are also developed when controls are required by regulatory commitments. Also, Technical Specifications that have been relocated to licensee-controlled documents, in accordance with the NRC's Final Policy Statement on technical specification improvements, are generally transferred to the ECGs.

Similar to the Technical Specifications, the ECGs provide operability requirements, action statements, and surveillance requirements. The preparation and revision process for ECGs requires evaluation under the 10 CFR 50.59 safety evaluation guidelines. ECGs are reviewed by the PSRC and are approved by the DCPP plant manager. ECGs provide another means of ensuring operation within the design bases.

PG&E has also developed the outage safety scheduling program (AD8.DC55, Ref. 1.146) to minimize shutdown risk during DCPP plant outages, when Technical Specifications requirements do not apply for some safety-related equipment. The program identifies higher-risk activities and periods prior to entering an outage, so that comprehensive analyses can be performed and measures taken to optimize the availability of safety systems and electrical power sources. The fundamental goals for shutdown risk reduction are:

(1) To minimize the time at reduced inventory and mid-loop operation, and other higher risk evolutions

(2) To optimize the pathways for adding water to the reactor coolant system

(3) To optimize the availability of safety systems

(4) To optimize the availability of electrical power supplies

(5) To maximize work on safety systems during periods when the core is off-loaded, except for those systems required for spent fuel pool cooling

Contingencies are factored into the outage safety schedule such that a conservative level of equipment availability exists during high-risk periods. In some cases, this provides a margin between planned equipment availability and that required by Technical Specifications and the ECGs with regard to the safety functions of reactivity control, reactor coolant system inventory control, decay heat removal capability, containment capability, and electrical power availability.

This program incorporates recommendations from NEI, INPO, industry experience, and DCPP lessons learned. The program provides another level of assurance that DCPP remains within its design bases.

Review of Procedures Against Design Bases

From 1989 to the present, there have been a number of reviews that have helped confirm the consistency of operating, maintenance, and testing procedures with the design bases. This subsection describes these reviews. The majority have been associated with the Configuration Management Program (CMP), which was initiated in 1989, and with the related effort known as the DCM enhancement program (Refs. 5.1, 5.2)

As part of general program improvements that were implemented as part of the CMP, the following reviews were performed:

(1) A list of selected mechanical and electrical maintenance procedures that required consideration of design basis information was identified by the Maintenance organization, and was reviewed and adjusted by Engineering (Refs. 5.10 and 5.11). Design basis information is procedurally required to be considered when developing procedures, including maintenance procedures (Ref. 1.2)

(2) Plant surveillance procedures associated with the CMP draft pilot DCMs were reviewed by System Engineering to ensure that they reflected the appropriate design-basis functions and that these functions were demonstrated (Ref. 5.9).

In addition, a number of reviews were performed as part of the DCM enhancement program, between 1989 and 1994. Section (f), Design Basis Review and Documentation Program, provides a more detailed discussion of this program.

Specific reviews that were performed as part of the DCM enhancement program to verify the consistency of operating, maintenance, and testing procedures included:

(1) The enhanced DCMs received informal reviews from various groups. These reviews are now controlled by procedures (Ref. 1.20), which require that new or revised DCMs be reviewed to ensure that pertinent design basis information is translated into appropriate plant procedures.

(2) The Surveillance and Maintenance Requirements (SMRs) are the system, component, and structure functions and features that must be maintained and/ or demonstrated through test, inspection, or maintained in conformance with the design bases. The SMR requirements contained in many DCMs have been reviewed by the System Engineering group at DCPP. These reviews, which are now procedurally controlled (Ref. 1.20), are required to be documented on SMR review forms. The reviews ensure that there are tests, inspections, or maintenance procedures to verify the appropriate design basis requirements defined in the DCMs. As a result of these reviews, some tests and procedures were required to

be written or revised. The reviews that were conducted showed that very few tests and procedures needed to be prepared or revised, thus demonstrating that there was already good consistency between the procedures and the design bases. At the present time, the reviews have not been completed for all DCMs, and are currently ongoing. They are scheduled for completion during the first half of 1997. This initiative is discussed further in the section, "Conclusions and Future Actions."

(3) Selected operating, emergency operating, and annunciator response procedures were reviewed to ensure that they were consistent with the design bases contained in the enhanced DCMs. Initially, this was done for three systems (safety injection, component cooling water, and 4160V) and subsequently for another three systems (residual heat removal, auxiliary feedwater, and backup air/nitrogen supply) (Refs. 5.14, 5.15). The original plan to review more DCMs was discontinued because there were no significant findings for the systems that were reviewed.

The following additional reviews were conducted in developing this submittal.

(1) The Surveillance and Maintenance Requirements for four current DCMs (reactor coolant system, nuclear instrumentation system, plant protection system, and remote shutdown system), and for the Eagle 21 process protection system Safety Evaluation, were reviewed against Instrumentation and Controls surveillance and testing procedures. The purpose of the review was to determine if appropriate surveillance requirements were included in the procedures. The procedures were found to adequately address the SMR requirements.

(2) Operating, emergency operating, and annunciator response procedures were reviewed against the design bases contained in the enhanced DCMs for the residual heat removal (RHR) and emergency diesel generator (EDG) systems. The purpose of the review was to determine if appropriate design basis information contained in these DCMs was reflected properly in the operating procedures. As a result of this review, no safety-significant discrepancies were identified, but it was determined that additional reviews would be of value. These are discussed in the section, "Conclusions and Future Actions."

Setpoint Program

Additional assurance of consistency between operating and maintenance procedures and the design bases is gained through the setpoint program. Procedures exist (Refs. 1.42, 1.43, 1.135) to ensure the control of plant setpoints, including the identification of the setpoints to be controlled, the necessary organizational responsibilities and interfaces, calculation methodologies,

setpoint change control, and maintenance of setpoint information. The overall objectives of the setpoint program are to ensure that safety systems operate within their design bases and to prevent unnecessary challenges to safety and nonsafety-related systems that could degrade overall plant performance and reliability. These objectives are accomplished by:

(1) Establishing a consistent methodology for the calculation of setpoint values and documentation

(2) Ensuring that setpoints conform to system design basis requirements (including regulatory requirements, and commitments)

(3) Ensuring that setpoint changes are evaluated properly and controlled in a manner that supports overall plant configuration management

(4) Ensuring that setpoint values are listed, and available for use, in approved and controlled documents

A major effort in setpoint reconstitution began in 1988, as a part of the CMP, involving PG&E Engineering and Westinghouse personnel. The objective of the effort was to ensure that important setpoints were properly maintained in accordance with the plant design bases, and that appropriate calculation documentation was maintained.

The setpoint reconstitution effort consisted of:

(1) Identifying, on a system-by-system basis, the setpoints for that system

(2) Determining which of these identified setpoints were to be categorized as "engineering-controlled." Engineering controlled setpoints are setpoints that are safety-related, important to safety, or otherwise critical to system operation

(3) Determining and documenting specific design values for each engineering-controlled setpoint, via formal engineering design documentation

(4) Ensuring that these design values were properly incorporated into the plant information management system (PIMS) setpoint database

The bases required for setpoint calculations were taken from appropriate design basis documentation, such as plant calculations, NSSS information, accident analyses, vendor information, and DCMs.

The setpoint control reconstitution effort for Instrumentation and Controls and for MOVs was completed in 1996. Engineering-controlled setpoints are currently contained in the PIMS database.

Changes to controlled setpoints are processed in accordance with plant modification control requirements (Ref. 1.34), which ensures that appropriate design control measures, technical

reviews, safety evaluations, and other pertinent engineering and plant staff reviews and approvals are implemented.

Inservice Testing Program

Further assurance of consistency between design bases and test procedures is gained through the implementation of the Inservice Testing (IST) Program (AD13.ID5, Ref. 1.88). As required by 10 CFR 50.55(a), Technical Specifications stipulate that Inservice testing of ASME Code Class 1, 2, and 3 pumps and valves be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda. The development of the test requirements for the IST Program entails defining the appropriate design basis requirements for all pumps and valves within the scope of the program, and establishing the necessary test acceptance criteria to demonstrate the functional capability of the components. Design change procedures (Ref. 1.26) stipulate that changes to design basis information that could affect pump or valve testing or test results must be coordinated with the Inservice Test Program Coordinator to ensure that IST testing is in conformance with design bases.

The above programs and reviews provide improved consistency between design bases and plant operating, maintenance, and testing procedures. The change control process discussed below provides assurance that the consistency will be maintained.

Procedure Change Control Processes

This subsection describes the DCPP procedure change control processes, and how they help ensure consistency between design bases and procedures.

As described in Section (a), Design and Configuration Control Processes, change control processes maintain consistency between design bases and procedures by ensuring that changes to the design bases result in a corresponding change to procedures, and changes to procedures include a review of design bases to determine potential design basis impact. PG&E believes that its change control processes maintain consistency between the design basis requirements and the appropriate operating, maintenance, and testing procedures.

The majority of changes to operating, maintenance, and test procedures that can impact design basis consistency are the result of design changes. These design changes are initiated and controlled through the design change procedures (Refs. 1.19, 1.34, 1.35, 1.36). These procedures clearly identify necessary changes in operating, maintenance, and testing requirements brought about by a design change, and provide controls to ensure that other appropriate organizations are cognizant of such changes and make the necessary procedure changes. Required actions necessitated by such design changes are identified and tracked to ensure proper completion and closure. Change control processes were enhanced as part of the CMP and other initiatives in the

1989 time frame to include advance coordination reviews of design changes by the organizations that were affected prior to final approval of the design changes.

For changes necessitated by reasons other than design changes, the procedure change control process requires reviews for design bases and licensing basis impacts, including the proper consideration of 10 CFR 50.59 safety evaluations (Ref. 1.74).

Other controls providing additional assurance that these processes are being implemented in a manner to maintain design basis consistency are:

(1) New and revised surveillance procedures are reviewed independently by qualified personnel who are subject matter experts (Ref. 1.3).

(2) Procedure sponsors and Independent Technical Reviewers are qualified to perform 10 CFR 50.59 reviews and are knowledgeable about design basis requirements (Ref. 1.3).

(3) Design basis information is readily accessible to operation, maintenance and test procedure writers.

(4) Cross-discipline reviews are performed when another discipline will be affected by surveillance procedure changes, and walkdowns are performed when required (Ref. 1.3).

Training

Additional assurance regarding design basis and procedural consistency is gained from the extensive programs that provide training on numerous topics for Operations, Engineering, and supervisory Maintenance personnel. This training emphasizes procedural requirements and the importance of procedural compliance.

Engineering personnel who perform activities associated with the design change processes receive Engineering Support Personnel Training as described in Section (a), Design and Configuration Control Processes. This training acquaints them with the importance and the mechanics of accurately translating design change impacts to operations, maintenance, and testing organizations.

Operators receive extensive reactor operator licensing and requalification training that exercises the normal, abnormal, and emergency procedures in the classroom and on a simulator that is continually updated to reflect the design of the plant. Discrepancies are fed back to the procedure group for evaluation and incorporation. Feedback is also provided on shift when procedural discrepancies are identified.

Procedure sponsors and personnel who perform independent technical reviews of procedures are appropriately trained in procedure development and change activities, Licensing Basis Impact Evaluation (LBIE) screening, and safety evaluations as described in Section (a), Design and Configuration Control Processes. This training applies to Operations, Maintenance, and Engineering personnel.

Overall Effectiveness

This subsection describes the consistency between design bases and procedures as measured by various audits and assessments. Internal and external audits and assessments are discussed separately. Internal activities include QA audits, Safety System Functional Audit and Reviews (SSFARs) and Safety System Outage Modification Inspections (SSOMIs), as well as the results of Engineering Self-Assessments. External activities include NRC inspections.

Internal Audits and Assessments

PG&E's Quality Assurance (QA) Internal Audit Program has evaluated: (1) the consistency of operating, maintenance, and test procedures with design bases; and (2) the change control processes. These audits use vertical-slice audit techniques, and have consisted of SSFARs and SSOMIs, as well as performance-based Topical Audits that have covered the majority of DCPP safety systems. SSFARs, SSOMIs and Topical Audits are discussed in greater detail in Section (d), Processes for Problem Identification and Resolution. The SSFARs that have been performed have helped to demonstrate the consistency between design basis information and procedures. In some cases they have identified discrepancies in this area. For example, the SSFAR on the component cooling water (CCW) system noted that the acceptance criteria for CCW flow to the containment fan coolers did not adequately account for flow diverted to the fan cooler motor, and therefore, the flow rate specified by the Technical Specifications could not be assured (Ref. 2.10). For this issue, engineering calculations were performed to document the flow requirements, which were incorporated into a Surveillance Test Procedure (Ref. 5.32). Another SSFAR, on the auxiliary feedwater (AFW) system (Ref. 2.8), noted that containment isolation design bases were not properly translated into training lesson plans, emergency procedures, and the DCM.

The SSOMIs have provided significant information in terms of their review of modifications and design control processes. Although one of the early SSOMIs identified the need for improvement in the design change process (Ref. 2.6), later SSOMIs have shown a continuing improvement in the quality of design change packages, specifically with regard to the level of detail addressed in the performance of safety evaluations associated with the design change packages.

The results of the Engineering Self-Assessment, completed in March 1996 (Ref. 5.21), indicated that plant procedures, calculations and analyses were found to be generally consistent with the design bases. However, in a small number of cases regarding the AFW system, a lack of consistency between specific design basis requirements and surveillance procedures was identified. The discrepancies were found to be technically acceptable. No issue requiring an Operability Evaluation or a Nonconformance Report was identified, but procedure revisions were necessary in most cases. Examples of the discrepancies included:

(1) A surveillance test procedure allowed the AFW pump speed to be greater than that assumed in the system analysis (however, the resulting AFW flow rate was still within the maximum allowed by the Steam Generator Tube Rupture Analysis). This issue was addressed by engineering evaluations and calculations by taking into account "droop" phenomenon (speed decrease due to increased flow) (Ref. 5.33).

(2) A quarterly test allowed the AFW pump differential pressure to be higher than that allowed by piping design (although still within the maximum piping pressure allowed by stress analyses). The subsequent engineering evaluation determined that, due to the differences between the tests, the quarterly test would not exceed pipe design pressures (Ref. 5.34).

(3) A revision to an AFW surveillance test procedure was made without appropriate revision to the DCM and the FSAR (however, the test procedure revision had been reviewed for design basis impact and found to be acceptable through analysis). Procedural guidance was improved and the DCM was revised (Ref. 5.35).

The self-assessment also found minor discrepancies in surveillance tests developed by System Engineering personnel. These discrepancies were identified and corrected by Operations personnel before the tests were run, thereby demonstrating overall adequacy in verification processes. Nonetheless, the discrepancies were indicative of the need for improved engineering performance in the area of surveillance test development.

The self-assessment included a review of emergency diesel generator system surveillance tests and maintenance procedures. No discrepancies were identified.

The results of these audits and assessments have identified some issues related to inconsistencies between operating, maintenance, and test procedures and the design bases and some issues related to the change control processes. These issues have been or are being evaluated and addressed by corrective actions through PG&E's problem resolution processes. Collectively, there have been no significant programmatic deficiencies related to translation of design bases into operating,

maintenance, and testing procedures, and the issues identified have not resulted in a condition in which a system would have been incapable of performing its intended safety function.

External Audits and Assessments

The results of external audits and assessments, such as NRC inspections, serve as an important measure of the level of design bases and procedure consistency. They also help substantiate the findings of internal audits and assessments, and thereby provide a check of the effectiveness of DCPP auditing and problem identification processes. Certain NRC inspections have identified inconsistencies between design basis information and procedures. Examples include:

(1) Vendor instructions were not included in a work order on the turbine-driven AFW pump governor (Ref. 3.20).

(2) Acceptance criteria for EDG air starting system check valve leakage surveillance procedure did not ensure 45 seconds of continuous engine cranking, as specified in the FSAR Update (Ref. 3.7).

(3) Acceptance criteria were not included in the post-modification test procedure for the EDG fuel oil day tank level switch setpoint verification (Ref. 3.8).

(4) Operating procedure did not provide for verification of proper boron concentration in the cation bed demineralizer following regeneration to preclude an unplanned reactivity increase (Ref. 3.21).

(5) Surveillance test procedures for calibration of safety injection (SI) accumulator pressure instruments did not specify adequate initial test condition requirements to ensure that the pressure instrument calibration was not impacted adversely by other maintenance activities (Ref. 3.22).

(6) Surveillance procedure as written did not fulfill the requirements of Technical Specifications regarding accident monitoring instrumentation (Ref. 3.23).

These issues were addressed and appropriate corrective actions taken (e.g., revision of administrative procedures, STPs, operating procedures, and training), strengthening PG&E's overall program (Refs. 5.36 - 5.41). With respect to design bases and procedure consistency, the above issues did not represent a major challenge to plant safety or significant design basis programmatic deficiencies. This is taken as further evidence that consistency between design bases and procedures is generally well maintained. However, although the specific issues are not of major individual significance, they do indicate the need for continued emphasis on ensuring that applicable procedures (particularly surveillance procedures, due to their importance in verifying design basis parameters) properly reflect appropriate design basis requirements.

NRC inspections have identified issues similar to those identified in PG&E's internal audits. They have been dispositioned in the same manner as internally identified issues. PG&E believes that the significance of issues identified by external sources is comparable to those that were

internally identified in that they have identified no significant programmatic deficiencies related to the management of DCPP's design bases.

Summary Conclusions

PG&E believes that its operating, maintenance, and testing procedures adequately reflect the design bases for the following reasons:

(1) Original development of the DCPP operating, maintenance, and testing procedures were performed by experienced Operations and Maintenance personnel, who worked closely with Engineering, the NSSS vendor, and other equipment vendors

(2) Technical Specifications and ECGs that reflect the design bases are extensively used by operations personnel

(3) Design change and procedure change processes have maintained reasonable consistency of procedures with design bases

(4) Specific programs, such as DCM enhancement and setpoints, have reviewed procedural consistency with the design bases

As noted in the earlier discussion, PG&E has not yet completed the reviews of the DCMs against maintenance and testing procedures. These reviews are scheduled for completion during the first half of 1997. In addition, PG&E has determined that there would be value in performing some additional reviews of DCMs relative to operating procedures. These efforts will provide additional assurance of the consistency between the procedures and the design bases. Plans for these further reviews are discussed in the section, "Conclusions and Future Actions."

Extensive audits and assessments have demonstrated a reasonable consistency between procedures and design bases. Where problems have been identified, PG&E has evaluated these problems and implemented corrective actions to rectify them. While PG&E expects that future activities will identify other discrepancies, PG&E is confident that its processes for problem identification and resolution will properly resolve these discrepancies in a timely manner. Overall, PG&E believes that the operating, maintenance, and testing procedures adequately reflect the design bases.

(c) SYSTEM, STRUCTURE, AND COMPONENT CONFIGURATION AND PERFORMANCE

This section provides PG&E's response to the following NRC request:

> *(c) Rationale for Concluding System, Structure and Component Configuration and Performance are Consistent with Design Basis*

Introduction

PG&E believes that both the configuration and performance of structures, systems and components (SSCs) are consistent with the design bases. The rationale for this belief is different for the two topics of configuration and performance and the responses will, therefore, be provided separately.

PG&E's belief that the **configuration** of SSCs is consistent with the design bases is based upon the following:

(1) Specific configuration verification programs, including preoperational and startup testing programs and the Design Verification Program (DVP)

(2) Continuing SSC configuration verification, including operation and maintenance activities, modifications, testing, and inspections

(3) Adequate configuration control process and effective implementation

(4) Results of audits, assessments, and inspections that confirm that SSC configuration is generally maintained consistent with the design bases

PG&E's belief that the **performance** of SSCs is consistent with the design bases is based upon the following:

(1) Testing requirements and acceptance criteria consistent with design bases

(2) Pre-operational and startup testing

(3) Ongoing performance testing associated with operations, maintenance, and modifications

(4) Other specific programs, such as Generic Letter (GL) 89-10, Motor-Operated Valves, and System Engineering

(5) Analytical extrapolation, ensuring adequate performance for those SSCs that cannot be tested under design basis conditions

(6) The results of audits and assessments that confirm that the tests are properly performed, reviewed, and dispositioned

The following two subsections discuss configuration consistency and performance consistency separately. A common discussion of training and overall performance is then provided, followed by summary conclusions for this response topic.

Configuration Consistency

PG&E's belief that the configuration of SSCs is consistent with the design bases is based upon the following:

(1) Specific configuration verification programs

(2) Continuing SSC configuration verifications

(3) Adequate configuration control processes and tools implementation

(4) Results of audits, assessments, and inspections

These areas are discussed in the following subsections.

Specific Configuration Verification Programs

Programs that have included the review of SSC configuration consistency with design bases include the pre-operational and startup testing programs, the Design Verification Program (DVP), the development of the Component Database (CDB), and other focused design review programs. These programs are discussed below.

(1) Pre-Operational and Startup Testing Programs

A part of the pre-operational and startup testing programs included system walkdowns and equipment inspections that evaluated the configuration consistency of systems, structures, and components with the design bases.

Prior to commercial operation, configuration of DCPP systems was verified during the turnover of plant systems from PG&E's construction organization to the startup organization, and subsequently during turnover from the startup organization to the plant Operations department. Plant systems were walked

down and determined to adequately meet configuration requirements. Discrepancies were documented and resolved, and appropriate design documentation was revised to reflect as-built configuration.

(2) Design Verification Program

The DVP (Ref. 4.3) also contributed to the assurance of SSC configuration consistency with the design bases. The DVP consisted of an Independent Design Verification Program (IDVP) managed by Teledyne Engineering Services, and an Internal Technical Program (ITP) performed by PG&E. In combination, these programs provided a comprehensive review and/or reanalysis of the design of Unit 1 safety-related structures, systems and components, including:

(a) The seismic design of the containment structure, the auxiliary building (including the fuel handing building), the turbine building, and the intake structure

(b) Safety-related large bore piping and pipe supports, and generic and sampling review of small bore safety-related piping and pipe supports

(c) Reviews of the seismic qualification of all safety-related mechanical, electrical and instrumentation and control systems equipment, Class I electrical raceway and HVAC ducting and supports, and a sampling of instrumentation tubing and supports

Walkdowns were conducted to verify that correct as-built configuration was used in the analyses. When inconsistencies were identified, physical modifications were made, if necessary, or analyses revised to confirm the acceptability of the configuration ("Independent Design Verification Program - Diablo Canyon Nuclear Power Plant - Unit 1," prepared by Teledyne Engineering Services, dated October 10, 1983, Ref. 4.2).

The DVP also reviewed, on a sampling basis, other selected design areas, including pipe break analysis, system and component design, electrical design, separation for fire protection and quality assurance. Specific systems selected for review included the: (1) auxiliary feedwater system, (2) control room ventilation and pressurization system, and (3) the safety-related portions of the 4160-volt electrical system (Ref. 4.2). Walkdowns were conducted to verify as-built conditions in each of these individual activities. When inconsistencies were identified, they were resolved.

The IDVP included a review of a sample of construction work to verify that the quality of the construction was acceptable and that the as-built condition was consistent with the design. This review was documented in Interim Technical Reports (ITRs) and the final IDVP Report. The IDVP found the work to be satisfactory (Ref. 4.2).

The NRC staff's review of the IDVP Final Report was contained in SSERs 18, 19, 20, and 24 (NUREG - 0675, "Safety Evaluation Report Related to the Operation of Diablo Canyon Nuclear Power Plant, Units 1 and 2," prepared by the U.S. Atomic Energy Commission, dated October 16, 1974, with Supplements, Ref. 3.4). The NRC, the Atomic Safety and Licensing Appeal Board (ASLAB), and the Advisory Committee on Reactor Safeguards (ACRS) concluded that the Design Verification Program had been completed successfully and that there was reasonable assurance that Unit 1 adequately met the conditions of the license.

PG&E conducted an Internal Review Program (IRP) for Unit 2 to address those issues identified for Unit 1 by the IDVP, the ITP, and the NRC. Seismic reviews and reanalyses, including walkdowns, were conducted for Unit 2 safety-related systems, structures, and components, similar to those of Unit 1. Nonseismic and generic issues that were identified for Unit 1 were reviewed for applicability to Unit 2. The total of these efforts provided an extensive review of the design bases and configuration of the plant. The results of the IRP were reviewed and found acceptable by the NRC in SSERs 29, 30, 31, and 32 (Ref. 3.4).

In testimony before the California Public Utilities Commission in the Diablo Canyon Rate Case, it was stated that:

> *The magnitude of PG&E's efforts in verifying the plant's seismic design was unprecedented in the history of the nuclear industry.* (Ref. 4.4)

(3) Component Database Development

During 1984 and 1985, a CDB was developed as part of the Plant Information Management System (PIMS) (Ref. 1.18). As part of this development effort, accessible components were walked down to verify nameplate data and location. While this was not designed to be a complete verification of system and component configuration, it did serve as an additional means to check the consistency of design documentation with physical as-built conditions. This CDB serves as a central repository for component design-related information that is used extensively for design, procurement, material control, and work control functions. The CDB has been a valuable tool in maintaining design and plant configuration control.

(4) Regulatory Guide (RG) 1.97 Review Project

In response to concerns identified during a design change, PG&E conducted a self-initiated detailed review of the redundancy, electrical isolation and separation, qualification and other aspects of the RG 1.97 systems. This review was conducted from 1989 to 1994. This effort involved detailed review of system configuration consistency with design bases and resulted in greater awareness of potential failure modes and implementation of design changes to provide improved redundancy and electrical isolation and separation (NCR DC0-91-EN-N005, Ref. 5.66, Operability Evaluation OE 91-13, Ref. 5.18).

(5) Breaker Review Project

As a follow on to the RG 1.97 Review Project, the Breaker Review Project was conducted from 1992 to 1994. This review was initiated due to the potential compromise of redundant Class I functions by Class II loads on some Class I circuits. The review involved verification of configuration consistency with the design bases (NCR DC0-91-EN-N005, Ref. 5.17; Operability Evaluation OE 91-13, Ref. 5.18; and PG&E Letter No. DCL-92-246, Ref. 5.19).

Collectively, the programs discussed in this subsection have contributed significantly to establishing SSC configuration consistency with the design bases.

Continuing SSC Configuration Verifications

Other activities that continue to verify configuration consistency with design bases include operations walkdowns, maintenance activities, modification implementation, testing and inspections. Each of these is briefly described below.

(1) Operations

Operations personnel are required to perform routine walkdowns of plant systems to verify proper operational configuration, alignment, and material condition. This process is controlled by the following procedures:

(a) General Authorities and Responsibilities of Operating Shift Personnel (OP1.DC10, Ref. 1.133)

(b) Nuclear Operator Routine Plant Inspections (OP1.DC3, Ref. 1.132)

(2) Maintenance

Preventative and corrective maintenance activities result in plant personnel reviewing existing configuration and verifying that this configuration is in conformance with design requirements when problems or concerns are identified. Corrective actions for configuration inconsistencies are implemented as appropriate. Post-maintenance testing and system restoration are accomplished as the final steps to maintenance activities, to ensure that the plant physical configuration is consistent with appropriate design documentation and operational procedures (AD13.ID4, Ref. 1.87).

(3) Modifications

Additional assurance of SSC configuration consistency with design bases is gained through the established processes for design change development and implementation of plant modifications. (CF3, Ref. 1.19; CF3.ID9, Ref. 1.26; CF4, Ref. 1.34; and CF4.ID3, Ref. 1.36) The process often starts with the review of the as-built condition of the design. Changes to the design bases must be incorporated into the appropriate design documents (CF3.ID9, Ref. 1.26). After completion of plant modification, required as-built documentation is completed, the modified configuration is tested to ensure performance consistency with design basis requirements, and then restored to appropriate operational configuration (AD13.ID2, Ref. 1.86).

(4) Testing and Inspections

In addition to the post-maintenance tests and post-modification tests described above, other testing and inspection activities serve to verify configuration consistency with design bases (Control of the Surveillance Testing Program, Ref. 1.85 and Inservice Testing Program, Ref. 1.88). Inservice inspection activities ensure that the physical configuration of plant components within the scope of the ISI program are repaired and maintained in accordance with appropriate design basis documentation (AD5.ID2, Ref. 1.90).

(5) System Engineering Program

The System Engineering Program plays an important role in ensuring consistency of SSCs configuration with the design bases. DCPP maintains a System Engineering Program that is administered procedurally (TS5.ID1, Ref. 1.89). The purpose of the System Engineering Program is to provide appropriate technical support for the plant. Individuals designated as System Engineers maintain overall

"ownership" of a particular plant system or multiple systems and are considered the primary contact for questions regarding the design bases for their system.

The System Engineer also is responsible for temporary modifications to the system and monitors these modifications during the monthly system walkdowns. Extensions of these temporary modifications beyond a refueling cycle requires management approval. This ensures that temporary modifications receive the proper review and that impacts on the design bases of the system are understood fully.

The System Engineer normally serves as sponsor for design changes to the system. As the design change sponsor, the System Engineer coordinates implementation to ensure that configuration changes are incorporated into plant operational, maintenance and surveillance procedures, the CDB, appropriate training materials, and other relevant documentation. As the design change sponsor, the System Engineer ensures the as-built configuration is reflected in plant drawings and procedures (CF4.ID3, Ref. 1.36).

Configuration Control Processes and Tools

SSC configuration consistency with design bases is maintained through the effective implementation of the processes that control work and necessary changes. These processes, which have been described in Section (a), Design and Configuration Control Processes, provide the necessary attributes to recognize changes, evaluate their impact, and maintain configuration consistency with the design bases.

There are also a number of tools that have been developed to improve the ability to effectively implement these processes. These tools include:

(1) Enhanced DCMs as described in Section (f), Design Basis Review and Documentation Program

(2) The CDB, discussed earlier in this section, which serves as a central repository for component design-related information

(3) The Procedure Commitment Database

Performance Consistency

PG&E's belief that the performance of SSCs is consistent with the design bases is based upon:

(1) Test requirements and acceptance criteria consistent with the design bases

(2) Preoperational and startup testing

(3) Ongoing performance testing

(4) Other specific programs, such as GL 89-10 (Motor-Operated Valves) and System Engineering

(5) Analytical extrapolation

(6) Results of audits, assessments, and inspections (discussed in the subsection on overall performance)

These areas are discussed in the following subsections.

Test Requirements and Acceptance Criteria

The first step in establishing that SSC performance is consistent with design basis requirements is to ensure that design bases have been translated appropriately into testing requirements and associated acceptance criteria. PG&E's discussion in Section (b), Design Basis Translation to Operating, Maintenance, and Testing Procedures, provides the basis for the conclusions in this area.

Pre-Operational and Startup Testing

The pre-operational and startup testing programs, described earlier in this section, also provided a solid initial baseline for determining system, structure and component performance consistency with the design bases. Plant systems were walked down and performance-tested at the component and system level and determined to adequately meet performance requirements.

During pre-operational testing, initial plant performance was measured against specified acceptance criteria. Results were documented in pre-operational test procedures, and in the cases where specified acceptance criteria could not be met, corrective actions were implemented. This testing permitted the baselining of system and component performance characteristics, which established the benchmark values for acceptance criteria for subsequent system and component testing (Ref. 1.142).

Following receipt of a low-power license, a startup testing program, which included an initial criticality and low-power physics program and a power-ascension test program, was undertaken to demonstrate that initial core performance and plant performance were consistent with the plant design bases. For Unit 1, a series of Special Low-Power Tests were performed, including natural circulation and simulated loss of all site AC power. In addition to providing experience and information to plant operators, these tests provided actual plant data for verification of design conservatism and improvement of plant modeling and analysis.

Ongoing Performance Testing

To maintain continuing consistency between SSC performance and the design bases, periodic testing is performed on plant systems and components. Testing is also performed whenever changes that could affect component or system performance are made. Such testing verifies system and component alignment and conformance with design documentation, and demonstrates the capability of the systems to meet the acceptance criteria of their specified testing requirements. Some of the key testing that is routinely performed includes:

(1) Surveillance Testing

Periodic and conditional surveillance tests are performed to comply with Technical Specification requirements, licenses, and other documents relating to maintenance and operation of the plant (AD13.ID1, Ref. 1.84; and AD13.DC1, Ref. 1.85). These tests include those associated with the Inservice Testing (IST) program for pumps and valves (AD13.ID5, Ref. 1.88). These tests confirm that the systems and components are capable of meeting the acceptance criteria consistent with design basis requirements.

(2) Post-Maintenance Testing

As part of planning maintenance activities, post-maintenance test requirements necessary to confirm acceptable performance and operability are identified (AD13.ID4, Ref. 1.87). These tests are performed following the maintenance activities to provide continued performance consistency with the design bases.

(3) Post-Modification Testing

Similar to maintenance activities, modifications also require the identification of appropriate testing to confirm the acceptable performance of the components and systems affected (AD13.ID2, Ref. 1.86). This testing provides an acceptable level of confidence that the modified equipment will function as designed and is properly integrated into plant systems.

After these testing activities, verification of configuration restoration and realignment is performed to ensure that the as-left condition of the plant is consistent with appropriate design documentation (Operations Management, OP1, Ref. 1.61). Taken collectively, PG&E's extensive ongoing testing programs provide a regular check on and assessment of performance consistent with the design bases.

Other Specific Programs

PG&E has implemented a number of other specific programs that have provided additional assurance that SSC performance remains consistent with the design bases. Some of the more notable programs include:

(a) Implementation of GL 89-10, Safety-Related Motor-Operated Valve (MOV) Testing and Surveillance (PG&E Letter No. DCL 94-262, 1994, Ref. 5.5). To implement the requirements of this generic letter, a significant review of system design bases, configuration, and component (MOV) functional performance was performed. Testing was performed to confirm the acceptable performance of the valves. Periodic testing continues as part of this program (MA1.ID1, Ref. 1.141).

(b) Implementation of GL 89-13, Service Water System Problems Affecting Safety-Related Equipment (PG&E Letter No. DCL 90-027, Ref. 5.3 and PG&E Letter No. DCL 91-286, Ref. 5.4). To implement the requirements of this generic letter, reviews of the plant heat removal and ultimate heat sink functions were performed, including system and component design basis requirements and associated system and component performance test requirements.

(c) Electrical Calculation Enhancement Program (NCR DC0-92-EN-N010, Ref. 5.24). This was a long-term result of the Station Blackout compliance to 10 CFR 50.63. The program updated electrical design calculations and provided a common database for related information in all calculations.

(d) Design Calculation Index. This index was the result of a Design Calculation Continuous Improvement (CI) team. The program provided a common database for related information of design calculations.

(e) Implementation of the Maintenance Rule (MR). To implement the new MR requirements, system design bases were reviewed, and performance parameters were identified for safety-related components and components important to safety. A monitoring program was established as required by the MR to ensure component performance is monitored against appropriate acceptance criteria and trended to ensure adequate maintenance requirements are in place.

(f) Long Term Seismic Program. This program, a 1983 license condition, required PG&E to reevaluate seismic design bases. PG&E performed extensive state-of-the-art geological studies, a probabilistic risk assessment, and evaluated the fragility of plant SSCs. Plant design and design bases were reviewed, and walkdowns of selected SSCs were performed. The program was completed in 1988 and accepted by the NRC in 1991.

(g) System Engineering Program. The System Engineering Program, described earlier in this section, also plays an important role in assuring consistency of SSCs

performance with the design bases. System Engineers are familiar with the performance, acceptance criteria, and bases for surveillance testing on their systems.

Analytical Extrapolation

The final element in determining that SSCs performance is consistent with the design basis requirements is often analytical extrapolation. Since testing frequently cannot be performed at design basis conditions, analysis is used to project the performance of systems, structures, and components based on testing at conditions that can be achieved. Thus, the specification of required testing, acceptance criteria, and design analysis needs to remain consistent. PG&E's processes for design control and the procedure change process, discussed in the response to Section (a), Design and Configuration Control Processes, provide assurance of consistency.

Training

Operations personnel who perform testing meet the requirements of training programs that are accredited by the National Academy for Nuclear Training. Licensed operator training complies with 10 CFR 55 and ANSI N18.1-1971, Section 5.5. Maintenance personnel who participate in testing activities are qualified in accordance with training programs that are also accredited by the National Academy for Nuclear Training. Maintenance supervisors receive additional training in the following topics that relate to maintaining design and configuration control:

(1) Revising plant procedures

(2) LBIE screen training

(3) Design basis configuration maintenance impacts

(4) Design changes

(5) Surveillance Test Procedures

(6) Technical Specifications

(7) Work Orders

(8) Supporting work packages in the field

System Engineers who participate in testing activities and review of test results receive Engineering Support Personnel Training as described in Section (a), Design and Configuration Control Processes.

Overall Effectiveness

The internal and external assessments of SSC configuration and performance are discussed below.

Internal Audits and Assessments

Numerous internal audits and assessments have evaluated the consistency of SSC configuration and performance with the design bases. These include the SSFARs, the SSOMIs, and topical audits that have been performed by the Quality Assurance organization as well as the results of an Engineering Self-Assessment. The details of these audit programs, including the extent and depth of their coverage, are discussed in Section (d), Processes for Problem Identification and Resolution.

(1) Quality Assurance Audits

The SSFARs, SSOMIs, and topical audits have been performed to determine whether:

(a) Configuration and conditions of the systems are in compliance with the applicable drawings and procedures.

(b) Testing is adequate to demonstrate that the system will perform the safety functions required by the licensed design bases.

Two topical assessments specifically focused on GL 89-10, Motor Operated Valves (Audit 94016I, Ref. 2.28), and GL 89-13, Service Water System Performance (Surveillance QP&A-93-0031, Ref. 2.39).

Overall, results from the audits performed to date have confirmed that the systems are capable of performing their designated safety function(s) and that there are no immediate operability concerns. In addition, they have not identified significant programmatic deficiencies. However, the audits have been intrusive and have identified some technical issues that could impact the functionality of the targeted systems and/or their supporting systems. Some of the findings have been significant. Examples of some of the more significant technical issues include:

(a) RHR pump performance not consistent with FSAR Update Figure 6.3-1. Results of full flow performance testing of RHRP 1-1 indicated that the pump performance would not meet that specified in the FSAR Update. Subsequent analysis by Engineering demonstrated that the injection profiles

used in the FSAR Update, Chapter 15, analyses could be met (Audit 93015I, Ref. 2.24).

(b) Valve 8703 single failure susceptibility. A review of the safety injection system configuration identified that a single failure of valve RHR-8703 could preclude establishment of RHR flow to the hot leg as required for long term recovery from a design basis LOCA (Audit 92001I, Ref. 2.16). An EOP was revised to provide compensatory actions in the event of failure of the valve during recovery from a LOCA. An STP was revised to specify the minimum flow requirements (Ref. 5.45)

(c) CCW flow balance issues. The assurance that adequate flow was available to ESF components during accident conditions could not be determined since neither procedural guidance nor adequate indication was provided to allow flow balance of the CCW system (Audit 90811T, Ref. 2.10). Engineering provided input regarding flow requirements, and an STP was developed to verify flow balancing once each outage (Ref. 5.46).

(d) Performance test results for CCW heat exchanger 1-2 predicted a heat removal capability less than the design basis value assumed in the accident analyses (Surveillance QP&A-93-0031, Ref. 2.39). Heat exchanger performance tests were reperformed with more accurate instrumentation, and the performance was acceptable. PG&E determined that there may have been times when the design basis requirements were not met, and issued a one-hour report pursuant to 10 CFR 50.72. The root cause was that design basis requirements were not adequately incorporated into test acceptance criteria. Corrective actions included revisions to calculations, the DCM, STPs, and an administrative procedure; and issuance of a new administrative procedure and an ECG (Ref. 5.47).

(e) PIMS Component Database accuracy. The usability of the CDB was impacted adversely by ineffective procedures for the processing of as-built information in a timely manner, untimely resolution of previously identified concerns associated with the CDB, workload management and prioritization decisions. A general lack of understanding and sensitivity was identified relating to the importance of the CDB relevant to plant configuration management. The improvement of the CDB is an ongoing process. The importance of CDB accuracy was emphasized in training (Ref. 5.50).

(f) Blowout panels in the auxiliary building that were credited in the outside containment pressure /temperature transient analyses were found to be blocked

closed (Audit 93014I, Ref. 2.23). Labels were added to the blowout panels to alert personnel to the design basis function of the panels (Ref. 5.48).

Each of these issues has been evaluated and corrected, and has served to strengthen the design and configuration control processes and prompt additional reviews to identify and resolve similar problems.

(2) Self-Assessments

The 1996 Engineering Self-Assessment (Ref. 2.40) was conducted to determine the overall effectiveness of engineering activities and programs. Some of the assessment comments were:

(a) Surveillance tests and one post-modification test for the AFW system were reviewed. Results were acceptable, and interviews with the System Engineers confirmed Engineering involvement and review.

(b) One post-modification flow test of the AFW turbine-driven pump failed the acceptance criteria. The results of the test were acceptable when adjusted for differences between the test conditions and the accident scenario. A "Prompt Operability Assessment" (see Section (d), Processes for Problem Identification and Resolution) documented the acceptability of the test results. A calculation, a Technical Specifications interpretation, and an STP were revised to reconcile the differences (Ref. 5.49).

(c) Monthly walkdowns were not routinely performed as required by procedure.

(d) The overall performance and effectiveness of the System Engineering program was viewed as a strength.

At the completion of the assessment, a report was issued, the assessment team debriefed Engineering supervision and management, developed action plans to address the issues, and an issue closure team (ICT) was formed that tracked them to completion using PIMS.

The general conclusion from these audits and assessments was that although problems were identified, safety systems would have performed their intended safety functions and generally conformed to the design bases.

External Audits and Assessments

The results of external audits and assessments, such as those performed by NRC inspections, are presented in this subsection. They provide a valuable source of information regarding the

effectiveness of processes for maintaining the consistency between design bases with plant configuration and performance, and support the findings of internal audits and assessments.

Between 1990 and 1996, the NRC documented approximately 30 instances where the physical configuration of the plant was verified to be consistent with the design documents. Systems addressed in these verification activities included RHR, SI, CS, CCW, AFW, Emergency Boration, Fuel Handling Building HVAC, Auxiliary Building HVAC, Control Room Ventilation, ASW, Instrument Air, Solid State Protection, and EDG. It can be inferred from these findings that the consistency between design bases and the physical plant generally is well maintained. However, there were instances in which the NRC identified areas of inconsistency between configuration and the design bases; some examples were:

(1) A reactor coolant system loose parts monitor strip chart recorder was out of service in the control room, contrary to FSAR Update requirements (NRC Inspection Report 90-30, Ref. 3.26). An investigation of the Vibration and Loose Parts Monitor (VLPM) output determined that there was no vibration or loose parts. An interim data collection and review system was established. New VLPM equipment was purchased. An administrative procedure was written for the control of equipment not required by Technical Specifications, and an ECG was specifically prepared for the VLPM (Ref. 5.44).

(2) A test gauge was installed on the discharge of the CCW pump for an extended period of time without the required jumper log in place (Ref. 3.38). A review was conducted and no other similar deficiencies were identified. A lessons-learned memorandum was issued, and training was provided (Ref. 5.42).

(3) A jumper was installed on a Class 1E bus to receive power for a spent fuel pool cooling pump from a nonvital bus, and no safety evaluation was written (NRC Inspection Report 96-09, Ref. 3.28). The FSAR Update was revised to provide clarification on the classification of the power supply, a review of the FSAR Update was completed to identify and correct incorrect or incomplete information, and an administrative procedure was revised (Ref. 5.43)

(4) The licensee discovered tube fretting damage at baffle plate locations in both of the redundant Unit 2 CCW heat exchangers tubes in March 1993. (NRC Inspection Report 93-34, Ref. 3.30) Tube plugging was completed where necessary, and an operating procedure was changed (Ref. 5.51).

Other configuration inconsistencies have been identified as a result of NRC inspections, including breaker mispositioning (NRC Inspection Report 93-32, Ref. 3.6; and NRC Inspection Report 94-24, Ref. 3.27) and improper valve orientation (NRC Inspection Report 91-10, Ref. 3.11). In response, personnel training, documentation enhancements, and additional work instructions were completed (Refs. 5.55, 5.56, and 5.57).

The NRC routinely reports on the observation of the performance of STPs. Typical statements of results are:

The inspectors found that the surveillances reviewed and/or observed were being scheduled and performed at the required frequency. The procedures governing the surveillance tests were technically adequate and personnel performing the surveillance demonstrated an adequate level of knowledge. The inspectors also noted that test results were appropriately dispositioned. (NRC Inspection Report 96-16, Ref. 3.14)

Numerous Inspection Reports note observations of personnel performing surveillances. A number note procedural errors such as:

(a) *The inspector found that the licensee had not assured that the ASW system maintenance and surveillance controls were sufficient to assure system operability.* (NRC Inspection Report 94-08, Ref. 3.29) To address this finding, an administrative procedure and STP changes were made (Ref. 5.53).

(b) *The licensee identified that MSSVs were incorrectly set during periodic testing due to setpressure inaccuracy introduced by the use of valve specific correction factors.* (Ref. 3.37). In response, a new STP was written to implement an augmented test program, personnel counseling was completed, and a project manager was appointed to manage the augmented test program. (Ref. 5.54)

Inspection reports have noted observations regarding the System Engineering Program: "*There is not a clear definition or understanding of system engineer responsibilities during system testing. . . The NRC views the increased involvement of the system engineer as a strength of the outage testing program; however, increased system engineer involvement without clear definition of system engineer responsibilities during the conduct of testing creates an increased potential for errors in communications*." (NRC Inspection Report 94-28, Ref. 3.31) A lessons-learned memorandum was issued, and an administrative procedure was revised to clarify the responsibilities in the performance of STPs (Ref. 5.52).

The problems identified have not had a significant impact on the safe operation of the plant, and the appropriate corrective actions have been taken. It is concluded, therefore, that although there were weaknesses in procedural implementation, no significant programmatic concerns regarding consistency of design bases with plant configuration and performance have been found.

Summary Conclusions

PG&E believes that there is adequate consistency between the plant design bases and plant configuration and performance and that the applicable processes are effective in maintaining this consistency. PG&E's extensive pre-operational and startup testing programs combined with the

IDVP provided a firm foundation for ensuring consistency with the design basis. As part of normal operation and maintenance activities, plant personnel monitor the operational state of the plant, including configuration and performance acceptability, using controlled work processes and supporting tools. System and component testing demonstrates that performance requirements are satisfied. Various programs such as implementation of GL 89-10 and 89-13, electrical calculation enhancements, implementation of the Maintenance Rule, System Engineering Program, and the Long Term Seismic Program, provide additional assurance of consistency. Frequent audits and surveillances are performed to ensure that this design basis consistency is maintained. When problems do occur, they are addressed through PG&E's corrective action programs. Overall, PG&E believes that system, structure, and component configuration and performance are consistent with the design bases.

(d) PROCESSES FOR PROBLEM IDENTIFICATION AND RESOLUTION

This section provides PG&E's response to the following NRC request:

> *(d) Processes for identification of problems and implementation of corrective actions, including actions to determine the extent of problems, action to prevent recurrence, and reporting to NRC*

Introduction

PG&E believes that it has effective processes for the identification and resolution of problems. This belief is based on the following:

(1) The extent and thoroughness of existing processes for problem identification

(2) The existence and implementation of an effective Quality Assurance (QA) audit program

(3) The existence and implementation of a problem resolution process that evaluates and determines causal factors and extent of problems; defines and implements corrective actions, including those that prevent recurrence; and reports problems to the NRC

(4) The results of audits and assessments that evaluated and determined the effectiveness of the problem identification and resolution process

This section is divided into the following discussion elements:

(1) Processes description

- (a) Processes for the identification of problems
- (b) Significance classifications and associated levels of evaluation
- (c) General problem resolution process flow from identification through resolution

(2) Training

(3) Overall effectiveness of problem identification and resolution process in supporting design and configuration control

Process Description

Processes for Problem Identification

There are a number of processes at Diablo Canyon Power Plant (DCPP) that provide for the identification and resolution of problems. Many of these processes control activities associated with operating and maintaining the plant, and those that directly relate to maintaining design and configuration control were already described in Section (a), Design and Configuration Control Processes. Others include internal audits and assessments, external audits and assessments, assessments of external industry issues and events, input from vendors and suppliers, and employee observations. The processes for problem identification include:

(1) Routine work processes

(2) Internal audits and assessments

(3) External inspections and assessments

(4) External industry issues and events

(5) Employee observations

These processes are discussed in detail below.

(1) Routine work processes

The primary source of problem identification is simply people observing problems as a part of routine daily work. Personnel are trained to document problems that they observe. In addition, a number of specific work processes are designed to detect and/or address problems that can impact design and configuration control. Examples of these processes include:

(a) Supplier audits and surveys (AD9.ID11, Ref. 1.91)

(b) Processing of 10 CFR 21 notifications (CF7.ID2, Ref. 1.92)

(c) Processing of information provided by suppliers (CF7.ID3, Ref. 1.121)

(d) Materials receipt inspection (AD9.ID7, Ref. 1.94)

(e) Identification and resolution of loose, missing or damaged fasteners (AD4.ID8, Ref. 1.95)

(f) Plant leakage evaluation (AD4.ID2, Ref. 1.96)

(g) Performance monitoring equipment calibration and usage control (MA2.ID2, Ref. 1.97)

(h) Readiness-for-restart program (OP1.ID1, Ref. 1.98)

(i) Balance-of-plant reliability program (OM4.ID11, Ref. 1.99)

(2) Internal audits and assessments

Internal audits and assessments are key mechanisms designed to identify and prevent problems. These mechanisms aim to ensure that the necessary processes and controls are in place to comply with the requirements of 10 CFR 50, Appendix B, and that performance is monitored in accordance with those processes. The internal audit and assessment processes include:

(a) Nuclear Quality Services (NQS) audits

(b) Inspection programs

(c) Self-assessments

Each of these is briefly described below.

(a) Nuclear Quality Services (NQS) Audits

This process monitors the adequacy and effectiveness of the QA program through a comprehensive system of internal audits. As prescribed by 10 CFR 50, Appendix B, these audits are performed in accordance with written procedures or checklists by trained personnel not having direct responsibilities in the areas audited. Audit findings are documented and addressed in accordance with the Problem Identification and Resolution process (OM7.ID1, Ref. 1.56), the Quality Evaluation Process (OM7.ID2, Ref. 1.107), the Nonconformance Report Process (OM7.ID3, Ref. 1.57), and the Internal Auditing process (OM4.ID13, Ref. 1.108), which are described below.

The primary method employed by the QA (now NQS) department to verify the control and implementation of the DCPP design and licensing bases is the technical audit program. In the past 10 years, this program has consisted primarily of three types of audits:

(i) Safety System Functional Audit and Review (SSFAR) - SSFARs are “vertical-slice” audits of selected safety-related systems to assess their operational readiness by reviewing their design bases, operation, maintenance, and testing. SSFARs were initiated in

1989 and were patterned after the NRC's Safety System Functional Inspection (SSFI) process. SSFARs consist of six individual inspection elements: design, operations, maintenance, testing, documentation, and training. The SSFAR is an intensive effort, performed by a team comprised of approximately 12 to 18 persons and lasting for about four to seven weeks. The SSFAR is accomplished through:

A. Review of design and vendor documentation, procedures, and training materials

B. A physical inspection and walkdown of the system

C. Interviews with cognizant personnel

The objective of the SSFAR is to verify:

- System design is consistent with the design bases
- Testing is adequate to demonstrate that the system will perform the safety functions required by the design bases
- Maintenance is adequate to ensure operational readiness
- Training of appropriate plant personnel is adequate
- Procedures for operating normal, abnormal, and alarm response conditions are adequate
- Configuration and conditions of the system are in compliance with the applicable drawings and procedures

PG&E has performed SSFARs on five systems. The results from each are briefly summarized as follows:

A. Vital electrical system (1989) - The SSFAR concluded that "*electrical distribution systems had been adequately designed and configured to meet the intent of the original design and licensing basis*." However, the SSFAR added that increased attention is required to maintain the completeness of the design basis documentation (QA Audit 89800T, Ref. 2.7).

B. Auxiliary Feedwater (AFW) system(1989) - The SSFAR concluded that "*the AFW Design Criteria Memorandum (DCM) developed as part of the design bases review was effective in summarizing and defining the design bases of the system*." However, the SSFAR also identified a number of concerns regarding the functionality of the AFW and interfacing systems (QA Audit 89808T, Ref. 2.8).

C. Component cooling water (CCW) system (1990) - The SSFAR identified a number of concerns regarding the functionality of the CCW and interfacing systems. However, the SSFAR concluded that "*there were no immediate operability concerns ....*" (QA Audit 90811T, Ref. 2.10).

D. Intermediate head safety injection (IHSI) system (1992) - The SSFAR identified a number of concerns regarding the functionality of the IHSI and supporting systems. However, the SSFAR determined that "*there were no immediate operability concerns ....*" (QA Audit 92001I, Ref. 2.16).

E. Residual heat removal (RHR) system (1993) - The SSFAR identified weaknesses that challenged the design and licensing bases and, in some cases, resulted in reduced design margin. However, the SSFAR concluded that the RHR system "*would perform its intended function, and that it was in conformance with its design basis and licensing requirements*" (QA Audit 93015I, Ref. 2.24).

The issues identified in these SSFARs have been addressed through PG&E's problem resolution program. Resolution activities include a range of improvements, from new enhanced electrical calculations to training.

Prior to SSFARs, system audits had been performed to assess the adequacy of plant systems. In contrast with SSFARs, which provide for an assessment of most aspects of a system (including design, operation, surveillance, maintenance, QA, and material condition, as well as accident analyses and other supporting calculations), system audits were performed primarily to verify the effectiveness of implementation of QA requirements pertaining to

operation, surveillance, maintenance, and modification activities of a system. Thus, system audits were typically more limited in scope and less resource intensive. Nevertheless, the system audits provided an effective means for identifying problems with system configuration control and confirming the design control of such systems. System audits were performed on the auxiliary saltwater system (Ref. 2.1), the control room ventilation system, (Ref. 2.2) the emergency diesel generators (Ref. 2.3), and the 4160 volt system, (Ref. 2.4).

(ii) Safety System Outage Modification Inspection (SSOMI) - SSOMIs are vertical-slice audits of plant modification and technical support activities performed for refueling outages. SSOMIs focus on the operational readiness of safety systems through assessments of design modifications and their implementation as well as through testing. SSOMIs were developed and implemented to evaluate the effectiveness of the design change process to ensure that design changes were effective in accomplishing their objectives and that the plant design bases were preserved in the process. SSOMIs are patterned after NRC inspections of the same name. They have six elements: modification design, procurement, modification installation, testing, documentation, and training. SSOMIs typically consist of two parts: a design assessment prior to the outage, and an implementation assessment during the outage. SSOMIs verify whether:

A. Appropriate programmatic controls exist for conducting design modification activities and outage technical support activities

B. Modification activities and technical support activities are being accomplished in accordance with established procedures and commitments

C. Modifications have been properly designed, installed, inspected, and tested to ensure proper performance of their intended functions

D. Modifications are consistent with design bases and design margins of systems have not been compromised

E. Modified portions of the systems are ready for plant startup and technical support activities are performed in accordance with approved procedures.

SSOMIs have been performed for refueling outages for each unit since the second refueling outage of Unit 1. Major design changes that have been assessed include: Boron Injection Tank Removal, digital feedwater system installation, 10 percent atmospheric dump valve upgrade, installation of the sixth emergency diesel generator, reactor coolant system resistance temperature detector bypass elimination, Eagle 21 process protection upgrade, and 4-kV breaker replacements (SSOMI surveillances and audits; Refs. 2.5, 2.6, 2.9, 2.11, 2.12, 2.14, 2.15, 2.17, 2.18, 2.22, 2.25. 2.27, and 2.30).

(iii) Topical Audits - In addition to SSFARs and SSOMIs, performance-based audits of selected technical subjects or programs are performed to verify consistency with applicable regulatory criteria and implementation in accordance with established procedures. Typically these audits are performed to verify the adequacy of key engineering programs. In addition, focused assessments are performed occasionally on selected systems or subsystems based on specific concerns relating to system performance. Topical areas for assessment are selected based on various factors, including program/system safety significance, identification of problems, and regulatory activity. Topical audits typically assess related design, maintenance, and testing activities to ensure that the design bases are implemented appropriately and that applicable regulatory requirements are met.

These topical audits often focus on key design basis subjects and have included the following activities: procurement (Refs. 2.13, 2.20, and 2.26); equipment qualification (Ref. 2.23); 10 CFR 50, Appendix R (Fire Protection) (Ref. 2.29); and Generic Letter (GL) 89-10 (Motor-Operated Valves) (Ref. 2.28).

The performance of these three types of audits has been valuable in contributing to design and configuration control for the following reasons: (1) the vertical-slice type audits are beneficial in that they examine multiple aspects of system performance, and address interrelationships with other key systems and programs, including support system dependencies; (2) the scope of these three types of audits includes testing and maintenance activities, and therefore helps verify that design basis information is reflected properly in the appropriate maintenance and testing requirements; (3) these three types of audits include the review of pertinent training

information, thereby ensuring that appropriate design and design basis information is conveyed in training lesson plans; (4) the audits include verification of as-built configuration and system restoration and alignment, to ensure that the system physical configuration is in conformance with design basis requirements; (5) these audits review surveillance test results to ensure that components are capable of satisfying their intended performance requirements; (6) the audits address post-modification and post-maintenance testing to ensure that modification and maintenance activities do not impact component design basis functional capability; and (7) finally, the audits provide valuable insights to senior management with respect to making enhancements to design and procedural controls.

The key elements of this system of technical audits are in place today. However, since the most significant safety systems already had been assessed, no additional SSFARs have been performed since the RHR SSFAR in 1993. In lieu of the manpower-intensive SSFARs, smaller, more focused system assessments recently have been performed on an as-needed basis when questions arise as to the functional readiness of a given system. Examples of this type of assessment are the reactor vessel refueling level indication system (RVRLIS) and the reactor coolant pump oil collection system.

For the Unit 2 sixth refueling outage and Units 1 and 2 seventh refueling outages, the "implementation" phase of SSOMIs have been performed in conjunction with comprehensive technical outage audits, designated as Technical Support Outage Assessments (TSOAs) (Refs. 2.31, 2.33, and 2.45). The progression into the TSOA format was the result of two changes made to plant outage audits: (1) audit scope was augmented to include assessments of technical issues not directly related to design changes, and (2) that portion of the assessment that pertained solely to oversight of construction activities was transferred to the Maintenance section of NQS. However, the TSOA continues to evaluate field changes as well as testing activities and results to ensure that the design bases, as assessed during the "design" phase of SSOMIs, continue to be met.

To streamline its audit process and to facilitate its ability to provide timely oversight of ongoing activities, the NQS department recently converted to a system of continuous audits of various plant functions. For example, the NQS Engineering Assessment Group (EAG) currently performs quarterly audits of ongoing engineering activities. The transition from the traditional "batch" audit program to a continuous audit process was made to provide

the EAG with the flexibility to respond in a timely fashion to continually changing engineering activities and technical issues. Rather than devoting a single block of time for assessing a particular subject once during an audit period, the engineering activities associated with that subject may be assessed periodically throughout the audit period. This approach is patterned after the NRC resident approach of continuous inspections.

In addition, the inclusion of an "emerging issues" element into the scope of the quarterly audit enables the audit team to provide timely oversight for emergent engineering work. Recently implemented, the overall scope of these audits includes the elements described above, including performance-based assessments of plant systems and design changes that evaluate the control and implementation of the design and licensing bases. Each quarter the specific scope of these audits is developed based on a review of ongoing engineering activities, key technical issues, and significant engineering programs. The review includes consideration of the safety significance to plant operation. For example, the 1996 fourth quarter audit assessed the implementation of the Maintenance Rule as well as the Inservice Testing and System Engineering programs. During the first quarter of 1997, selected design changes for implementation during the Unit 1 eighth refueling outage will be assessed.

Collectively, the scope of the QA audit process in examining safety-related systems has been extensive. Table 2 provides a summary of the selected internal audits, surveillances, and assessments that have focused on design and configuration control along with the specific systems and topical areas that these audits have addressed. The vast majority of these audits and assessments have been performed by the QA organization in accordance with the requirements of its auditing process (OM4.ID13, Ref. 1.108).

The audits and assessments performed are shown as the rows in Table 2, and the safety systems and topical areas as columns. The systems are listed in decreasing order of risk significance, based on current PRA core damage frequency. For each audit or assessment performed, the systems and topical areas that were addressed are marked.

TABLE 2

	SYSTEM*																			
Audit Subject*:	ELEC	SEISMIC	ASW	EDG	FIRE	AFW	RCS	RHR	SSPS	CCW	HVAC	RPS	CVCS	SI	MS	SFP	CONT**	CS**	MFW**	NI**
ASW System Audit			■		■															
CR HVAC System Audit											■									
DG System Audit	■	■		■																
4.16 kV System Audit	■										■									
1R2 SSOMI							■			■					■	■	■			
2R2 SSOMI		■	■				■	■			■	■		■						
Electrical System SSFAR	■	■		■	■						■									
AFW SSFAR	■	■		■		■											■			
Westinghouse Supplier Audit							■					■		■						
1R3 SSOMI	GS				■		■		■	■	■	■					■		■	
CCW SSFAR	■	■								■										
2R3 SSOMI	■												■							
1R4/2R4 SSOMI Design	■							■			■				■		■			
1R4 SSOMI - Installation				■				■			■				■		■			
2R4 SSOMI - Installation				■		■	■	■	■	■				■	■		■	■		■
SI SSFAR	■	■		■										■						
1R5 SSOMI - Design		■	■			■		■			■						■			
1R5 SSOMI - Installation		■	■			■	■	■			■								■	
1R5 Maintenance Quality Assessment							■								■					

TABLE 2 Key System and Topical Area Audits and Assessments

	SYSTEM*																			
Audit Subject*:	ELEC	SEISMIC	ASW	EDG	FIRE	AFW	RCS	RHR	SSPS	CCW	HVAC	RPS	CVCS	SI	MS	SFP	CONT**	CS**	MFW**	NI**
Comprehensive Procurement Program Audit	■			■				■												
2R5 Maintenance Quality Assessment Air Operated Valves	■						■				■		■		■				■	
2R5 SSOMI	■	■		■	■			■												
ASW Performance-Based Review			■							■										
Environmental Qualification Program Audit							■	■			■				■					
RHR SSFAR	■	■						■												
Westinghouse Support of Response to NRC Generic Letter 89-13 Inspection - CCW Temperature Evaluation			■					■		■	■		■	■						
1R6 SSOMI - Design		■	■			■	■			■	■								■	
1R6 SSOMI - Installation	■		■	■		■	■				■	■			■					
Generic Letter 89-10 Program Audit	■	■	■			■		■			■		■	■			■	■	■	
Post Fire Safe Shutdown					■															
2R6 Technical Support Outage Assessment	■		■	■						■							■	■		
Procurement				■																
1R7 SSOMI - Design	GS	■	■	■									■				■		■	
1R7 Technical Support Outage Assessment	G		■	■			■	■					■		■			■	■	
1996 Annual/Biennial/Triennial Fire Protection					■															
2R7 Technical Support Outage Assessment	■	■		■			■	■		■		■		■	■					
Third Quarter 1996 Audit - NTS Activities	G	■	■	■	■										■	■				
1996 Engineering Self-Assessment				■		■														

TABLE 2 (continued)

* KEY:

SSFAR - safety system functional audit and review
SSOMI - safety system outage modification inspection

#R# - unit number, refueling outage number
ELEC - electrical (site except as noted)
S - site electrical (25 kV and lower)
G - grid electrical (230 kV and higher)
ASW - auxiliary saltwater
CR - control room
CS - containment spray
HVAC - heating, ventilation, and air conditioning
AFW - auxiliary feedwater
CCW - component cooling water
RHR - residual heat removal
SEISMIC - seismic qualification and SISIP
RPS - reactor protection
SSPS - solid state protection system
CONT - containment
SFP - spent fuel pool
EDG - emergency diesel generators
RCS - reactor coolant system
NI - nuclear instrumentation
SI - safety injection
CVCS - chemical and volume control system
MS - main steam
MFW - main feedwater
FIRE - fire protection and Appendix R

** CONT, CS, MFW, and NI were not rated with respect to "core damage frequency." Containment and containment spray are important to mitigating a containment release.

(b) Inspection Programs

PG&E performs inspections of quality-related and nonquality-related systems, equipment, and materials at DCPP as a means of ensuring adequacy in performance. These inspections, often referred to as Quality Control inspections, are performed in accordance with established procedures (AD5.ID1, Ref. 1.125), and generally involve direct inspection of items; however, monitoring of the process used to control quality may also occur. In addition, these inspections may occur during or after work activities, or may occur independent of specific activities. These formal inspections are in addition to the routine inspections or checks that are performed by foremen or supervisors in the normal course of overseeing the status of maintenance and modification activities. The identification of adverse conditions also is documented in accordance with procedure (OM7.ID1, Ref. 1.56).

(c) Self-Assessments

The PG&E Engineering department has recently (1994) started performing self-assessments. These self-assessments have, among other things, examined the effectiveness of Engineering staff in understanding, maintaining, and communicating the DCPP design bases. The assessments are performed to evaluate Engineering effectiveness, from a qualitative "how-are-we-doing" perspective and from a results-oriented objective comparison of work products against requirements.

Early self-assessments were conducted with an informal process that permitted qualitative judgments, but they did not provide the documented evidence necessary to demonstrate compliance or problems with procedures, design bases, etc. This informal process made effective response to findings difficult. Consequently, in 1996 the Engineering Self-Assessment Team (ESAT) performed an assessment in accordance with DCPP procedure (OM4.ID12, Ref. 1.100) and NRC Inspection Procedures 37550, "Engineering," and 40500, "Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems."

Systems and activities were selected for review in the ESAT based on safety significance and prior assessment or audit history. The selected systems and activities were rigorously examined. The plant configuration was compared to calculations, drawings, the Final Safety Analysis Report (FSAR) Update, DCMs, and other requirements. Operations and maintenance activities were observed and personnel were interviewed.

Engineering staff responses to previously identified problems were also reviewed. Results, including source documentation, logic, and conclusions, were documented in sub-assessment reports for each aspect of engineering activity examined, and collectively summarized in the ESAT final report. Results requiring action were also documented in the formal problem identification and corrective action process. Forty-four Action Requests (ARs)[9] and five Quality Evaluations (QEs) were initiated.

PG&E has made extensive use of industry peers in its audits, inspections, and self-assessments. This external input has provided a broader perspective and has helped to strengthen existing programs.

(3) External Inspections and Assessments

Inspections and assessments performed by organizations that are external to PG&E also provide for problem identification. These organizations include the NRC and the Western Region Joint Quality Assurance Group (WRJQAG), a group of representatives from the QA departments of several utilities in the western U.S. that performs Joint Utility Management Audits (JUMAs) (Refs. 2.35, 2.36, 2.37, 2.38). Findings from these external inspections and assessments are addressed in a similar manner as internally identified problems. Further discussion on the results of such assessments are provided later in this section.

(4) External Industry Issues and Events

PG&E has a process for assessing industry operating experience (OM4.ID3, Ref. 1.101) that evaluates information from outside sources to prevent similar problems from occurring at DCPP. These outside sources include the NRC, the Institute of Nuclear Power Operations (INPO), and various vendors. Since 1980, industry operating experience information has been reviewed for DCPP as required by procedure OM4.ID3, except GLs and Bulletins issued since early 1994 that require formal response. The GLs and Bulletins are addressed by the Nuclear Safety Assessment and Licensing group as required by procedure (XI1.ID1, Ref. 1.102), "Regulatory Correspondence Processing."

If there is an issue with potential for impact on the DCPP design or licensing bases, the issue is considered a potential problem and an AR is prepared and processed

[9] The AR is a computer record of a specific action, documented in the Plant Information Management System (PIMS). ARs have been in use since June 1985. QEs are a formal problem classification. ARs and QEs are further explained in the following pages.

through resolution in accordance with the problem resolution process governed by OM7 (Ref. 1.55).

(5) Employee Observations

The Problem Identification and Resolution process (Ref. 1.56) is the general process for the identification of problems. Employees who discover a problem (regardless of classification) are responsible for reporting the problem (by initiating an AR or NCR, or by reporting the problem to a supervisor).

In addition, PG&E has an Employee Concerns Program (ECP) (Ref. 1.103) that allows for the anonymous identification of problems. The ECP (and its associated Hotline) serves as an alternative method for reporting concerns when employees desire anonymity or feel the established corrective action program has not resolved their concerns. More recently, PG&E also instituted an Event Trend Record (ETR) system for low-threshold problem reporting, using "gold cards." This system is briefly described in the following discussion.

Problem Significance Classifications

The Problem Identification and Resolution process (Ref. 1.56) provides for different levels of quality problem significance classification. The most significant level is a nonconformance and is addressed in accordance with the NCR process (Ref. 1.57). The next level is a quality problem requiring a QE, and is processed in accordance with the QE process (Ref. 1.107). The third quality problem level is an "A" type AR and is processed as a simple corrective action (Ref. 1.56). Instructions for determining the classification of such problems are provided in procedures (Ref. 1.56). Finally, nonquality problems are processed on ARs, and nonproblem events, issues, and conditions that may be precursors to quality problems may be directly entered into PIMS or documented in the ETR system using "Gold Cards."

The extent of evaluation, determination of cause, and corrective action is directly proportional to the significance classification. These classifications are briefly described as follows:

(1) Nonconformance Reports

NCRs represent quality problems that constitute significant conditions adverse to quality. A quality problem is classified as an NCR if it meets one or more criteria explicitly defined in DCPP procedures, including, for instance, a substantial programmatic or implementation breakdown in the QA program, or management direction for significant issues.

The NCR process (Ref. 1.57) contains the most rigorous controls for documentation, formal root cause analysis, reviews and approvals, and verification of corrective action completion. In general, a team of individuals, designated as the Technical Review Group (TRG), is assembled to review the issues and resolve the identified problems. If significant abnormal events require a more immediate or direct response by plant management than is normally afforded by a TRG, an Event Investigation Team (EIT), an Event Response Team (ERT), or an Integrated Problem Response Team (IPRT) (Ref. 1.104) is convened. These teams are assembled to provide management with a complete and timely understanding of a serious problem, and to provide an immediate response to correct or mitigate the consequences of the problem. Management personnel are responsible for chairing these teams and ensuring timely resolution to the problems.

The root cause for NCRs is formally evaluated and documented as a part of the problem resolution process (Ref. 1.105). The evaluation process uses a "Cause and Effect/Barrier Analysis" or an "Event and Causal Factors Charting Analysis," and is aimed at recognizing, understanding, and correcting the factors that caused the problem. However, alternate root cause analysis by a recognized, industry-accepted method may also be used with concurrence of a "Root Cause Advisor." A program designated as the Human Performance Enhancement System (HPES) program also may be used to identify, evaluate and correct the root cause of problems that occurred because of inappropriate action, near misses, or other potential problems (Ref. 1.106).

NCRs can be identified based on findings due to external processes, such as NRC inspections, or internal self-assessment activities, such as QA audits. NCRs can also be identified by DCPP staff during routine plant activities. Where reporting requirements are met, issues identified through NCRs are reported in Licensee Event Reports (LERs). Some recent examples of NCRs that have been reported in this fashion include (1) review pursuant to 10 CFR 50.59 of a procedure change (NCR N0002008, Ref. 5.25); (2) flashing of CCW at containment fan cooler units (NCR N0001977, Ref. 5.26); and (3) adequacy of 230-kV electrical system during outages (NCR N0001911, Ref. 5.27).

(2) Quality Evaluations

Problems at the next lower level of significance are classified as quality problems requiring a QE. The QE process as defined in OM7.ID2 (Ref. 1.107) is used to evaluate and resolve these problems. This classification is used for quality problems when requested by management, when required by other procedures, or for problems that do not require an NCR but do require a root cause analysis.

QEs receive root cause analysis when warranted by their significance (Ref. 1.105).

QEs also are used for the documentation and disposition of audit findings written by NQS internal auditors as a result of implementing the internal audit process (Ref. 1.108). Such a document, called a QE-Audit Finding Report or QE-AFR, is similar to the QE, but contains additional documentation provisions for the audit process.

In addition, a QE is occasionally used for the analysis and resolution of plant reliability issues on components or systems that are not quality-related (Ref. 1.99). When such use occurs, the document is identified as a Balance-of-Plant-QE or BOP-QE.

The QE process provides for the documentation of immediate corrective action, root cause determination, and corrective action to prevent recurrence. QEs are evaluated and resolved by the assigned department. This process provides management oversight of the planning and scheduling, and resolution verification, of quality problems. Root cause analyses are performed in the same manner as described for NCRs. Concurrence with planned corrective actions is provided by NQS.

(3) "A"-Type Action Requests

The next lower tier of quality problems is an "A"-Type AR (Ref. 1.56), which records the problem and allows assignment for resolution. This type of problem does not require root cause analysis. The resolution is documented in the AR in which the problem was reported.

(4) Gold Cards and Event Trend Records

A lower-threshold event reporting method designated as the "Gold Card" was instituted in early 1996. This mechanism is intended to allow identification of the occurrence of low-level, precursor-type issues and to provide for resolution before they become more significant. This mechanism is not to be used in lieu of an AR. The Gold Cards are collected and reviewed by NQS, and ETRs or ARs are initiated as required. Information from Gold Cards is entered into PIMS as an ETR and tracked to assist in the early identification of low-level performance trends or occurrences that might eventually lead to a more serious problem. Events may also be entered directly into the ETR system without the need for a "Gold Card."

General Problem Resolution Process Flow

The key steps in the flow of the problem resolution process are as follows:

(1) Upon identification, problems are normally documented in an AR (Ref. 1.56). An AR can be written by anyone in the organization and must specify the priority. If the problem affects, or could affect, plant equipment, the initiating department notifies the appropriate shift foreman.

(2) Problems transmitted to the shift foreman are reviewed to determine if there are immediate operability or reportability concerns. If the operability status of an item is not immediately known, the shift supervisor can request an evaluation by the appropriate Engineering personnel (Ref. 1.117). If the effect of the problem on equipment operability is not immediately apparent or cannot be immediately determined, a process designated as "Issues Needing Validation to Determine Impact on Operability" (INVDIO) (Ref. 1.118) is used. Specific time frames are allotted for these processes to ensure that the plant will operate safely and meet Technical Specifications (Ref. 1.119) and Equipment Control Guidelines (Ref. 1.114) requirements. The AR is then routed to the organization responsible for problem evaluation/resolution.

(3) The initiating organization ensures that the AR is reviewed and that the shift foreman has been notified if required.

(4) The initiating and/or responsible organization reviews the AR for significant quality problems that constitute a nonconformance.

(5) In addition to the reviews performed by the initiating and receiving organization, the AR is reviewed by other organizations and groups to ensure timely identification and implementation of actions for which they are responsible:

(a) The Daily AR Review Team (DART) reviews ARs that report problems. The reviews are conducted on the next working day following AR initiation. The DART is a cross-discipline group from Operations Services, Maintenance Services, Engineering Services (two members), and NQS. The team reviews new ARs to assess significance, ensure that immediate actions are initiated when required, elevate concerns requiring management attention, and identify adverse trends.

(b) Where needed, Prompt Operability Assessments (POAs) are performed by the Engineering staff. POAs document the rationale for why a degraded plant condition does not impact the ability of equipment to perform its

safety function. The POA procedure (OM7.ID12, Ref. 1.117) is activated after an AR is prepared or at any time during problem resolution in accordance with the AR procedure (OM7.ID1, Ref. 1.56), once the shift foreman and shift supervisor are notified of a problem that might have an impact on safety or equipment operability. The POA is normally performed and documented by the end of the operating shift during which it was determined that a POA is necessary, and is required by procedure to be documented no later than 24 hours following the determination that a POA is necessary.

Necessary verification and resolution for POAs is performed using the problem resolution process in accordance with procedures on ARs, QEs, NCRs, and Operability Evaluations (OEs). OEs are formal follow-up evaluations that are performed, as necessary depending on plant conditions and equipment operability issues, to specifically confirm the conclusions of POAs. The conclusion and basis of OEs must be documented and receive review and approval by the Plant Staff Review Committee (PSRC) and plant manager. The OE procedure (OM7.ID8, Ref. 1.109) is written in conformance with GL 91-18 (Ref. 3.19).

(c) Quality problems identified in ARs that involve an NCR or QE are reviewed by the DCPP Regulatory Services group to determine if the problems identified are reportable and then to initiate appropriate reporting actions (Refs. 1.57, 1.107, and 1.110). Operability issues are evaluated for reportability to the NRC in accordance with the requirements of various sections of 10 CFR 50. More specifically, reporting requirements on issues that may be pertinent to design and configuration control are primarily specified in the Technical Specifications (Special Reports related to equipment operability or potential performance degradation), 10 CFR 50.72 (Immediate Notification Requirements), 10 CFR 50.73 (LERs), and 10 CFR 50.9 (Completeness and Accuracy of Information). These requirements include specific provisions for the timing of reports, based on the significance and potential impact of an event. For instance, notification of certain plant events or conditions are required within one hour or four hours of event occurrence, and submittal of LERs is required within 30 days of event occurrence. These and other regulatory reporting requirements (e.g. 10 CFR 21), have been incorporated into the DCPP Technical Specifications as well as administrative procedures (XI1.ID2, Ref. 1.110). Occasionally, PG&E also provides voluntary LERs on events that are not required to be reported, but that may be of interest to the NRC for other reasons.

(6) Actions on ARs, QEs or NCRs are assigned to the department or section that has the responsibility for that particular aspect of the plant. Those individuals selected are required to have the expertise necessary to resolve the problems (Ref. 1.56).

(7) Root cause evaluations (Ref. 1.105) and the development of corrective actions to prevent recurrence are performed for NCRs and usually for QEs. For NCRs, the root cause analysis generally is performed by NQS personnel, and overall NCR resolution is reviewed by the PSRC for concurrence. NQS reviews QEs for concurrence with the resolution.

(8) Independent verification of the completion of corrective actions for NCRs and QE-AFRs is performed by NQS. Independent verification of completion of corrective action is required for QEs and "A" type ARs as well. It is usually performed by individuals who are not directly involved with the problem but are within the department responsible for the resolution of the problem.

(9) As follow-up to determine the effectiveness of corrective actions, the PSRC can request written updates six months after an issue is closed.

(10) Quality problem ARs are collectively reviewed to identify trends in accordance with a Quality Trend Analysis Program (Ref. 1.111). ETRs are created for quality problems and are reviewed to identify the presence of repetitive occurrences and adverse trends.

The processes for problem identification and resolution have been enhanced continually. These enhancements have reinforced the processes in areas of identified weakness based on lessons learned and on feedback from audits and assessments. Some of the more recent enhancements include:

(1) Formation of the DART to review ARs (OM7.ID1, Ref. 1.56) for significance and quality problem determination to ensure immediate actions are initiated as required, to elevate concerns requiring management attention, and to improve the POA process (Ref. 5.31)

(2) Enhancements to the NCR process (OM7.ID3, Ref. 1.57) to improve the monitoring of corrective action effectiveness and the timely resolution of NCRs

(3) Initiation of low-level event or condition trending in ETRs (OM7.ID10, Ref. 1.111)

(4) Enhancement of the QA internal audit process to identify generic implications (Ref. 1.108, OM4.ID13)

Training

NQS personnel who perform audits and assessments participate in Engineering Support Personnel (ESP) training and qualification programs pursuant to INPO requirements (TQ2.ID10, Ref. 1.140). Such training includes participation in ESP orientation, position-specific, and continuing training, as discussed in Section (a), Design and Configuration Control Processes. These personnel also have specific qualification guides that include specified knowledge and task requirements. In addition, NQS personnel who participate in engineering audits and assessments (including SSFARs and SSOMIs) participate in Lead Auditor Training as well as training in "Performance-Based Assessment" techniques. The latter consists of vertical-slice assessment approaches pertinent to performing SSFARs and SSOMIs.

NQS personnel who lead audits are qualified to the requirements of Regulatory Guide 1.144 (which endorses ANSI N45.2.23). Further, NQS personnel meet the qualification requirements of an "independent reviewer" pursuant to Regulatory Guide 1.8 and ANSI 18.1.

Engineering personnel receive training as described in Section (a), Design and Configuration Control Processes. One topic in Engineering Support Training is Problem Identification and Resolution, which discusses roles and responsibilities when a degraded condition is found, and the steps in initiating a POA.

Personnel who participate in the performance or review of root cause analyses receive qualification training in root cause analysis, in accordance with procedure (OM7.ID4, Ref. 1.105).

Overall Effectiveness

The overall performance of the problem identification and resolution processes is routinely assessed in various independent evaluations, including internal audits and assessments and inspections by the NRC. These processes, with particular emphasis on design basis conformance, have been determined to be generally effective through such assessments.

The discussion of performance results is divided into subsections focused on the following areas of performance:

(1) The ability to self-identify problems

(2) The effectiveness of the QA audit and assessment process

(3) The effectiveness of internal self-assessments

(4) The effectiveness of problem resolution processes

(5) Summary of effectiveness evaluations

The Ability to Self-identify Problems

PG&E believes that the problem self-identification process has been effective. Examples of two recent problems identified and addressed through these processes are:

(1) Flashing at the containment fan cooler units (CFCUs)

During the investigative phase to develop a design change to increase the CCW system design temperature, PG&E investigated the resulting change in the fluid conditions exiting the CFCUs for compliance with the design bases. A review of the calculation of record indicated that the proposed increase in design temperature would not cause boiling in the CFCUs. However, during this review, PG&E noted that the vital bus sequential loading of vital equipment during a loss of coolant accident (LOCA) concurrent with a loss of offsite power had not been analyzed.

During this sequence of events, the CFCU fans that were previously operating are deenergized but continue to windmill and to maintain forced convection of post-accident containment atmosphere over the CFCU coils. The CCW pumps also are initially deenergized, stopping the water flow, and restarted after a time delay. When this delay was taken into account, the resultant heat transfer caused the CCW inside the coils to boil off, resulting in a steam void and a subsequent water hammer when the pumps were reenergized. The DCPP design bases do not allow for CCW boiling at the CFCUs. This scenario has become a generic industry issue since neither Westinghouse (the CFCU manufacturer) nor other utilities considered it during the initial design (Ref. 5.26).

(2) Solid state protection system (SSPS)

During the development of the topical DCMs, an open item was identified regarding the scope of structures, systems, and components that are protected from earthquake-caused damage under the Seismically Induced Systems Interaction Program (SISIP). Circuits associated with signals generated at the 12-kV switchgear and main turbine front standard provide direct inputs to the SSPS for reactor trip under certain off-normal conditions. Damage to a combination of these circuits could render the SSPS unable to perform some of its safety-related functions.

An SISIP walkdown of these circuits was performed to assess their susceptibility to damage from nearby, nonseismically-qualified commodities. During this

walkdown, an engineer questioned whether these same circuits might also be subject to other hazards, such as a main steam line break. A second engineer on the walkdown, more familiar with high energy line break (HELB) methodology, recognized the significance of the question. Subsequent reviews revealed HELB vulnerabilities at DCPP that had broader, industry implications, resulting in NRC Information Notice 95-01. An Integrated Problem Response Team was assembled at DCPP to thoroughly investigate this event, determine if other, similar conditions existed, and to recommend appropriate corrective actions. (Ref. 5.64)

PG&E believes that these two problems and other findings that have been documented and resolved as a result of the general problem resolution process indicate that PG&E has been effective in monitoring its own activities and identifying problems.

The Effectiveness of the QA Audit and Assessment Process

The effectiveness of the QA program at DCPP has been evaluated through JUMAs conducted by the WRJQAG. These audits generally are performed on a two-year frequency and serve to evaluate the effectiveness of a licensee's QA program, including problem identification and resolution processes. The most recent JUMA of DCPP occurred in 1995 (Ref. 2.38) and specifically reviewed the effectiveness of NQS audits and assessments of design changes and modifications important to safety. The NQS monitoring and evaluation of the performance of the Engineering organizations were identified as a strength. In this same audit, however, a declining trend in the QA program effectiveness was identified. PG&E considered this decline to be unacceptable, and initiated an NCR to address this issue and implement corrective action to resolve the JUMA concerns (NCR N0001950, Ref. 5.28). The primary reason for the declining trend was that "*aggressive, critical evaluations of plant programs and organizational performance [are] not always displayed*." PG&E believes that the NCR actions resolve this issue.

It is worth noting, however, that the 1991 JUMA (Ref. 2.36) specifically recognized that the SSFAR and SSOMI reports were excellent, and the 1993 JUMA (Ref. 2.37) identified the SSOMI audit process as a QA strength. The 1989 JUMA noted that PG&E's audit program is implemented through a comprehensive system of well-planned and documented assessments of various activities. In addition, the NRC noted in an inspection on the SSFAR for the CCW system that "*both QA and the responding organizations committed considerable effort and resources to the audit and the resulting product was good*" (Ref. 3.33). Further, the SSOMIs were evaluated by the NRC in routine inspections. For instance, in an inspection report addressing the 1991 SSOMI, the NRC stated that "*the SSOMI was thorough and identified significant deficiencies, for which corrective actions were in progress*" (Ref. 3.5).

The NRC has reviewed the PG&E technical audit program in normal site inspection activities as well as special inspections. Through the program on Systematic Assessment of Licensee Performance

(SALP), the NRC consistently has recognized the depth of PG&E's technical audits and assessments. In particular, PG&E was recognized in 1989 as being "*on the forefront of the development of performance-based inspection activities with the implementation of SSFARs and the audit of their NSSS vendor*" (Ref. 3.41). While the 1989 SALP report also noted a concern with QA program audits of equipment suppliers, the QA audit programs were recognized as producing in-depth technical findings. Further, in the 1991 SALP report, the NRC considered as noteworthy the "*effective performance-based audit programs*" (Ref. 3.40). Although not specific to design audits, the 1992 SALP report noted that audits performed by the QA organization were generally good (Ref. 3.42). The report also noted that audits performed as QA initiatives showed significant technical depth and identified weaknesses in complex technical areas not typically reviewed by QA organizations. The 1994 SALP report characterized the independent NQS assessment of engineering activities as "*noteworthy*" and that it was performed in a "*probing, critical, and well-directed manner*" (Ref. 3.43). The 1996 SALP report observed that "*The audits conducted by the QA organization were supplemented by a department-level self-assessment. This initiative was new to the Diablo Canyon site and brought an improved technical quality to the performance review process and developed a sense of ownership which may promote improvement within the organization*" (Ref. 3.9).

The Effectiveness of Internal Self-Assessments

The effectiveness of PG&E's self-assessment activities was recently noted by the NRC. Again, as observed in the 1996 SALP report, the NRC stated that the department-level self-assessment "*improved technical quality to the performance review process ....*" The NRC also observed in the same report that "*engineering [staff] performed a number of thorough self-assessments, which combined with quality assurance audits were effective in identifying areas in need of improvement. Additionally, oversight groups were observed to be effective. Engineering generally demonstrated a strong safety focus and a positive approach to criticism*" (Ref. 3.9).

PG&E believes that the self-assessment process is a valuable tool to effectively identify problems and to focus attention on those areas in which the design bases could be compromised by routine plant activities.

The Effectiveness of Problem Resolution Processes

(1) QA Assessments

PG&E's QA program routinely conducts internal assessments of the problem identification and resolution processes. The following process characteristics are typically included in these assessments:

(a) Effectiveness of actions taken to resolve repetitive or similar concerns

(b) Identification of equipment and program trends

(c) Timeliness of corrective action implementation

(d) Consequence of untimely corrective action implementation

(e) Threshold at which problems are identified and addressed

(f) Adequacy of cause analysis

(g) Grouping of lower-level problems for review of generic or other concerns

The objective of internal audits typically is to assess the effectiveness of the corrective action program in resolving deficiencies, concerns, or problems that affect or potentially affect safety. Effectiveness is evaluated thorough the repetitiveness of equipment or program concerns, and through the identification and resolution of precursors to quality problems.

The results of the internal audits generally have confirmed that these processes are functioning properly. For instance, one QA audit report observed that, with some noted exceptions, there was "*evidence of quality problems being resolved in a timely manner, of corrective actions still being implemented long after quality problem closure, and areas where repeat problems were not recurring*" (Audit 960570014, p. 26, Ref. 2.46). Similarly, other QA audits observed that, with few exceptions, the "*NPG corrective action program was implemented effectively*" (Audits 95018I, p. 2; Ref. 2.43; and 94035I, p. 2, Ref. 2.44).

However, some significant exceptions had also been noted relating to corrective actions; the exceptions typically involved implementation of the corrective action process, such as "*effectiveness of some immediate corrective actions in preventing recurrence; ... timeliness of addressing ... findings; ... effectiveness of some corrective actions in preventing repeat problems ...*" (Audit 960570014, p. 26, Ref. 2.46). PG&E considers findings such as these to be useful in that they contribute to strengthening the problem resolution program.

(2) Self-Assessments

The results of a recent self-assessment concluded that the Engineering department had effective processes and generally had implemented them well, providing design and engineering services that conform to the design bases, and that "*Engineering was very effective at resolving most problems in a comprehensive manner*." Structures, systems and components were found to meet their key design bases and functional requirements. However, there were a number of areas in which discrepancies and problems were identified that required correction. PG&E

determined that these problems, while not individually significant, could cause degradation of configuration management controls if uncorrected (Ref. 5.21).

As a result of these self-assessment conclusions and past experience (Ref. 5.20), management established a formal full time team, the Issue Closure Team (ICT), to respond to the findings of the ESAT. A number of process enhancements and corrective actions were completed by this team. Examples included establishment of configuration management "Process Owners," training on licensing and design bases, and workload management and prioritization improvements. In addition, performance indicators were identified to monitor long-term performance and to ensure that problem resolution activities continue to be effective (Ref. 5.22).

(3) External Assessments

The NRC's observations of PG&E's problem identification and resolution processes have not always been favorable. However, PG&E believes that these concerns have been relatively few and that they have not involved significant programmatic deficiencies. For instance, the NRC review of root cause analysis (RCA) implementation expressed concern that not all NCRs included a systematic evaluation of root cause, and observed that "*there is no dedicated group of personnel with overall responsibility for the RCA program*" (Ref. 3.34).

Other NRC concerns indicated that "*while the initiation of corrective actions was effective, no person or group within the licensee's organization was responsible for driving the closure or resolution of action items*" (Ref. 3.35) or that "*the licensee's operability evaluations for deficiencies identified in the implementation of RG 1.97 was found to be weak in some areas*" (Ref. 3.36). PG&E believes that the necessary actions have been implemented to address these concerns. For example, as discussed earlier, currently the determination of cause for NCRs is formally evaluated and documented as a part of the problem resolution process. The NRC also stated more recently in Inspection Report 96-13 that PG&E "*had implemented an effective corrective action program, which encouraged identification and resolution of problems. ... [PG&E's] corrective action process, procedures and documents were acceptable to identify, process, track and conduct root cause analysis of problems and equipment deficiencies*." Further, the NRC noted that PG&E's "*operating experience feedback program was functioning effectively, with procedures that were excellent in forwarding events to appropriate plant personnel*" and that the "*self-assessment process was effective.*" (Ref. 3.12)

Summary of the Problem Identification and Resolution Process

PG&E recognizes that internal and external assessments have identified weaknesses with these processes. Over the past few years, these weaknesses have included lower-threshold problems, trending of lower-level problems, timeliness of resolution (which had been more of a concern for lower level problems), the effectiveness of corrective actions to prevent problem recurrence, and the timely identification of operability issues. PG&E believes that it has responded and is continuing to respond well to process issues that are identified so that it can improve these processes. PG&E also believes that the historical record of these processes, and the problems that have been identified and resolved through these processes, together demonstrate that there is a proactive attitude to search for problems and a strong commitment to safety at DCPP.

Overall, PG&E believes that its problem resolution processes have functioned and continue to function well. This conclusion was recently validated in NRC Inspection Report 96-13 (Ref. 3.12) with the finding, "*in general, that [PG&E's] corrective action program was well structured, provided an effective process for identifying, resolving and preventing plant problems, and was properly implemented.*"

Summary Conclusions

PG&E has found its problem identification and resolution processes to be sound, effective, and well-structured. The processes, particularly the QA audit process, have been effective in identifying problems in design and configuration management. Recent improvements in the corrective action process have strengthened the critical programmatic reviews. The self-assessment evaluations implemented through these processes have provided valuable checks on the viability of the existing programs for design and configuration control, and have given additional confidence that operation and maintenance of DCPP are in conformance with its design bases.

While issues with the problem identification and resolution process periodically occur, PG&E has addressed them and used them to continue to improve the existing program. Overall, PG&E believes that its problem identification and resolution processes have been effective in identifying and correcting design basis and configuration control problems.

(e) OVERALL EFFECTIVENESS OF PROCESSES AND PROGRAMS FOR CONFIGURATION MANAGEMENT

This section provides PG&E's response to the following NRC request:

> *(e) The overall effectiveness of your [PG&E's] current processes and programs in concluding that the configuration of your [PG&E's] plant(s) is consistent with the design bases*

PG&E's response to items (a) through (d) above provides a step-by-step description and assessment of the effectiveness of the engineering design and configuration control processes that have been in place at DCPP since plant licensing, including those that implement 10 CFR 50.59, 10 CFR 50.71(e), and Appendix B to 10 CFR 50. In addition, there has been a comprehensive discussion of PG&E's problem identification and resolution processes, including actions to determine the extent of problems and actions to prevent recurrence. PG&E's response to the NRC question on the Design Basis Review and Documentation Program (in the following section), delineates how the DCPP design bases were redocumented between 1989 and 1994 with a more detailed and specific baseline. How that program resulted in enhancing DCPP's processes and programs for controlling design changes and ensuring that the plant is operated within its design bases is also described. PG&E believes that these processes have contained the appropriate requirements, checks, and balances to provide the necessary assurance that the plant complies with and will continue to remain within its design bases as defined in 10 CFR 50.2. The remainder of this section discusses the basis for this conclusion.

The reviews conducted in preparation of this response have included analyses of numerous audits, assessments, and inspections that evaluated the results of the pertinent processes since 1987, and in some cases, before 1987. Included in these reviews were Design Criteria Memoranda (DCMs), design change and other key configuration control processes, as well as PG&E's process for making changes to operations, maintenance, and testing procedures. PG&E also has performed reviews of several safety-related plant systems and programs, including the emergency diesel generators, the auxiliary feedwater system, and the fire protection program. This effort also included reviews of selected QA audits and inspections as well as assessments by outside organizations, such as the NRC and the Western Region Joint Quality Assurance Group.

(e) Overall Effectiveness of Processes and Programs

Over the operating life of the plant, dozens of audits and surveillance reviews of plant systems have been performed by the Quality Assurance (QA) organization. Figure 4 shows the extent of these audits, which included five extensive Safety System Functional Audit and Reviews (SSFARs) and 13 Safety System Outage Modification Inspections (SSOMIs), and many routine system and process audits. Figure 5 shows that numerous NRC inspection activities reviewed the same systems and topics. Figure 4 audits often involved in-depth reviews by multiple personnel. Figure 5 represents the number of individual reviews or inspection activities relating to a particular system as identified in NRC inspection reports. While the two sets of numbers are not directly comparable, they do indicate that there has been significant scrutiny of most key systems, both internally and externally.

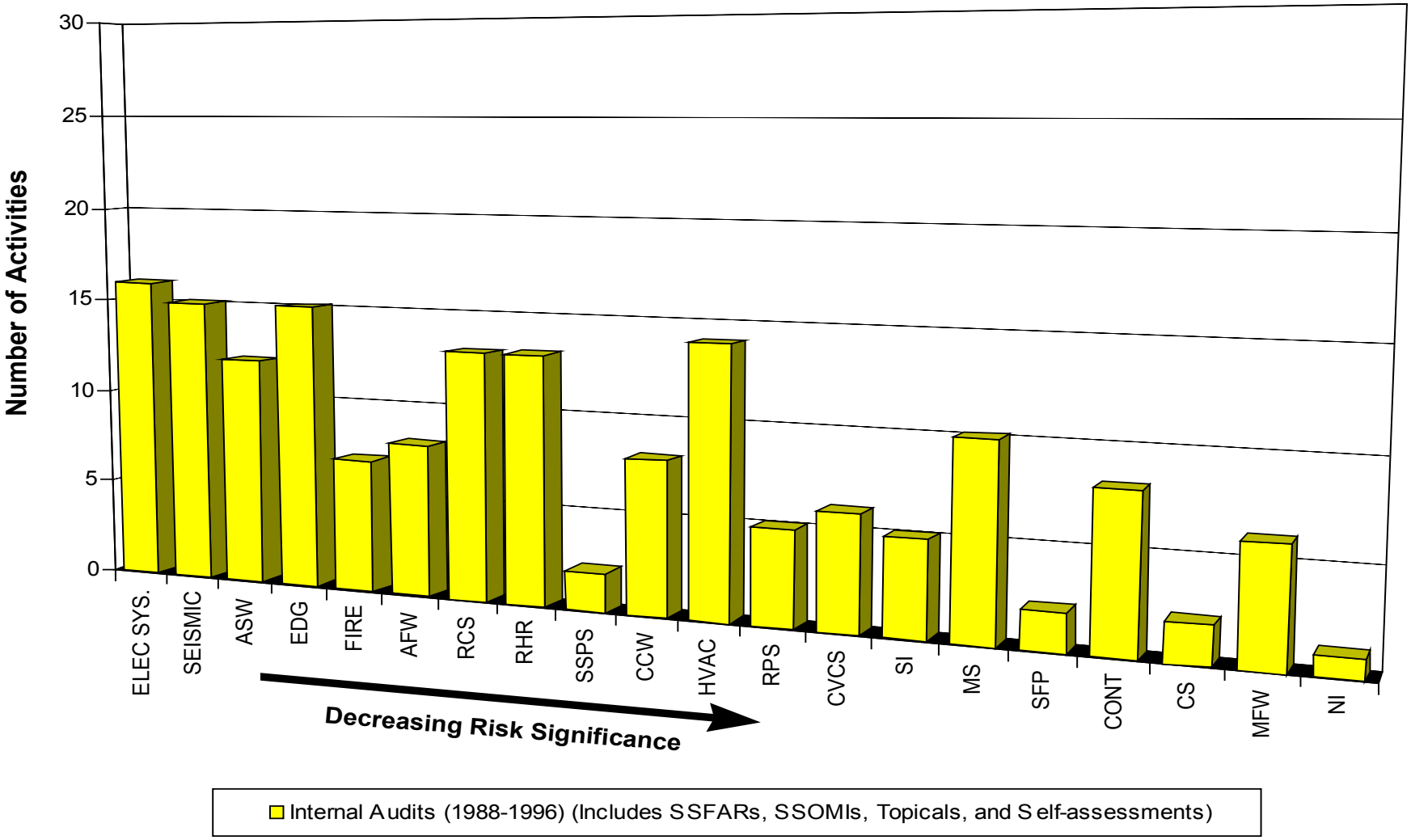
For example, as discussed in Section (d), Processes for Problem Identification and Resolution, the Engineering Self-Assessment Team "*found that engineering is generally effective, and programmatic controls meet regulatory standards*." The Joint Utility Management Audits (JUMAs) also noted that the PG&E audit program has been implemented through a comprehensive system of well-planned and documented assessments of various activities, and that the SSFARs and SSOMIs particularly were performed in an excellent manner. While several JUMA findings also were critical of PG&E's corrective action programs, PG&E has taken significant steps to address those findings.

The effectiveness of PG&E's processes and programs for ensuring design and configuration control during operation at DCPP can also be assessed through a review of Licensee Event Reports (LERs) and NRC inspection findings. Since 1987, the number of LERs involving design basis issues has remained low, typically on the order of one or two a year for each unit. In the majority of cases, design basis issues were identified primarily as a result of PG&E's processes and programs, and none of these events would have precluded a structure or system from performing its intended safety function.

A review of NRC inspection reports since 1987 has reflected similar results. A majority of NRC inspection reports indicates that the design control and design change processes appeared to be well-maintained and effective. The NRC also frequently observed that the knowledge of engineering personnel appeared noteworthy and that the consistency between design documentation and the physical plant configuration appeared to be generally well maintained. In those instances in which the NRC observed that plant configuration did not agree with design documentation, there was no significant impact to the safe operation of the plant.

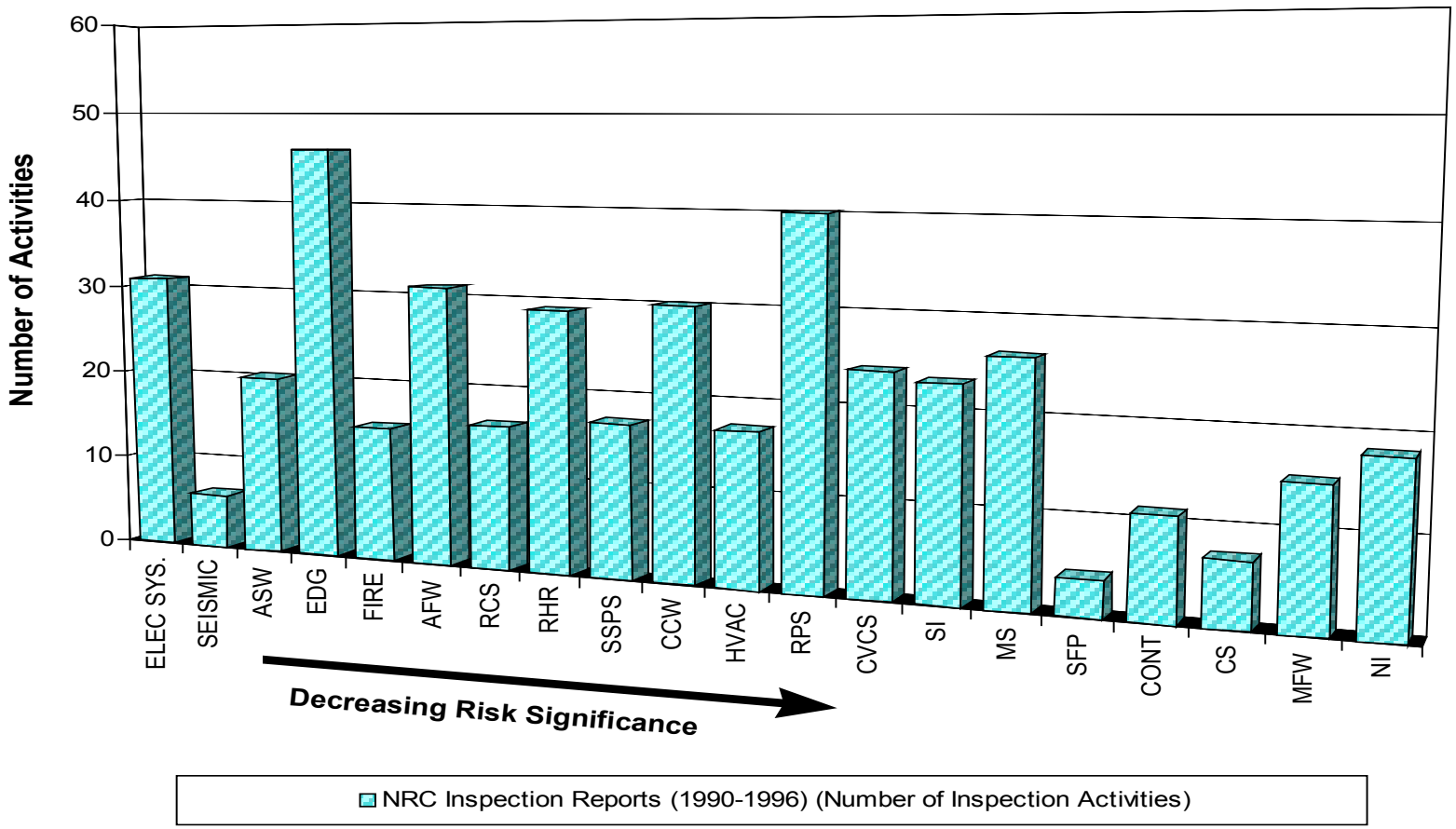
In summary, while configuration inconsistencies have been identified, PG&E believes that they would not have prevented the safe operation of the plant had they remained undetected. Based on these observations, PG&E believes that its processes and programs have been effective in ensuring design and configuration control during operation.

Figure 4: Internal Audits



NOTE: Legend for systems is given on page 98.

Figure 5: NRC Inspection Report Activities



NOTE: Legend for systems is given on page 98.

PG&E management recognizes that configuration control is and will continue to be a critical element in the maintenance and operation of DCPP. To that end, PG&E has continuously and voluntarily pursued actions beyond those required by the NRC to ensure that design bases are maintained during operation of the plant. PG&E actions in this regard have included major plant improvement projects that have been implemented over the past 11 years since commercial operation. Both the design and the design bases of the plant, as relevant to these major projects, were reviewed as a part of the design change process in implementing the plant modifications. Thus, these plant improvements have provided an additional mechanism for verifying conformance with the design bases. These projects include: (1) replacement of the 4-kV breakers; (2) replacement of the plant vital batteries; (3) replacement of the plant process computer; (4) removal of the boron injection tank; (5) elimination of the reactor coolant loop resistance temperature detector bypass; (6) replacement of the diesel fuel oil tank and improvement to the diesel fuel oil transfer system; (7) conversion to VANTAGE-5 nuclear fuel; (8) installation of new steamline break protection logic; (9) installation of the digital feedwater control system; (10) installation of the Eagle 21 process protection system; and (11) installation of a sixth emergency diesel generator.

Since PG&E acted as its own architect/engineer for DCPP's original design and construction, PG&E engineers and designers performed the majority of balance-of-plant design and much of the NSSS detailed design. PG&E has retained this responsibility throughout DCPP's history (in conjunction with Bechtel during the 1982 - 1985 period). This active participation has provided PG&E with a strong knowledge of how the plant meets the design bases, not only from an operating perspective, but also from a design engineering perspective. In addition, PG&E has managed the work of contractors and vendors and worked in close partnership with its key vendors (e.g., Westinghouse, by maintaining Westinghouse personnel at both DCPP and in the San Francisco PG&E engineering facilities; coordinating and sharing ongoing engineering, design and analytical work; and sharing design basis information electronically). This continued interaction between PG&E and Westinghouse personnel has produced a more complete and thorough knowledge of the plant design bases.

PG&E also has participated in numerous industry efforts to enhance plant performance in general, and to improve design and configuration control practices in particular. For instance, in response to NRC and industry concerns, PG&E established the system engineering program in the late 1980s to ensure timely and thorough engineering support for plant activities. In addition, while the Long Term Seismic Program (LTSP) was required as an operating license condition, PG&E pursued development of its Probabilistic Risk Assessment (PRA) program, not only as a part of, but subsequent to, the completion of the LTSP. Thus, PG&E was among the first licensees to use PRA in addressing plant safety and performance issues, including the NRC's requirements on IPE programs.

Further, PG&E participated aggressively with Westinghouse on Improved Standard Technical Specifications efforts, and DCPP was a lead plant in Region V (now Region IV) on Design Basis

Reconstitution. These additional efforts reflect that PG&E management is committed to ensuring that the plant continues to conform to its design bases.

In assessing the overall effectiveness of its processes and programs for configuration control, PG&E recognizes that qualified, committed plant personnel are vital to successful plant performance and that enhancements to the facility and a dedicated and well-trained plant staff are necessary to ensure the plant will continue to conform to its design bases. PG&E's philosophy has been to obtain and retain excellent personnel and to continuously develop their skills and experience.

As noted previously, in addition to operating and maintaining the plant since construction, PG&E has performed much of the DCPP design and construction internally, providing a challenging and rewarding environment for the nuclear power organization and a pool of knowledgeable design basis expertise. PG&E and its personnel excellence are demonstrated by its leadership positions in industry committees and standards groups, and by its identification of generic issues.

In addition to obtaining and retaining excellent personnel, PG&E supports their continued improvement through participation in industry activities, specific technical education and training, and an extensive DCPP training program. PG&E believes that the results of this focus on personnel have been reflected in DCPP's excellent operating record.

For the reasons discussed above, PG&E is confident that the DCPP design bases have been properly incorporated into plant design and are readily accessible through existing documentation and that these design basis requirements have been properly translated into operating, maintenance, and testing procedures. DCPP's system, structure, and component configuration and performance have been and are consistent with DCPP design bases. PG&E also believes that the DCPP design and configuration control processes have the required attributes to maintain design basis consistency. While problems have been and will continue to be found, they have been corrected through PG&E's processes for problem identification and resolution. Further, these identified problems have been used to make improvements to the processes. Accordingly, PG&E is confident that the current processes and programs provide reasonable assurance that the configuration of DCPP is consistent with the design bases.

(f) DESIGN BASIS REVIEW AND DOCUMENTATION PROGRAM

This section provides PG&E's response to the following NRC request:

> In responding to items (a) through (e), indicate whether PG&E has "*undertaken any design review or reconstitution programs, and if not, a rationale for not implementing such a program*"

Introduction

PG&E has previously implemented and currently maintains a design basis documentation program[10] that ensures that the design bases have been translated into, and have been properly maintained in the design, maintenance, testing and operation of Diablo Canyon. PG&E's confidence in the effectiveness of this program is based on the following factors:

(1) From 1989 to 1994, PG&E implemented a DCM program to provide enhanced documentation and verification of the design bases

(2) As a part of the enhanced DCM program, PG&E reviewed a number of Maintenance, Testing, and Operations procedures to ensure that they accurately reflected the design bases

In support of the basis for this conclusion, PG&E will discuss the development of the enhanced DCM program and the reviews that have been undertaken to ensure that it currently supports compliance with the design bases. PG&E will then discuss the DCM enhancement process, the verification of transfer of design bases, and the revision process for DCMs. In the following discussion, note that PG&E designates its documents "Design Criteria Memoranda," whereas the rest of the industry typically uses the term "Design Basis Documents."

[10] While PG&E initiated its Configuration Management Program (CMP) prior to NRC and NUMARC 90-12 (Ref. 5.29) guidance, PG&E believes its Design Criteria Memorandum enhancements and other CMP activities met the intent of NUMARC 90-12, and the NRC's policy on design bases reconstitution (57FR35455; August 10, 1992). These activities are often referred to as "Design Bases Reconstitutions." However, it should be recognized that while PG&E's program provided new, controlled primary source documents that collected and improved the design bases descriptions and consistency, and some new or "reconstituted" calculations, PG&E did not, in general, reperform calculations or analyses, because prior activities (as discussed in the Background and History paragraphs of the Introduction) had provided adequate confidence in the calculations.

Development of the Enhanced DCM

In 1987, based on the industry's move toward performance-based audits, PG&E began its own program of SSFARs and SSOMIs. After reviewing the results of these technical audits and NRC inspections, as well as the configuration management deficiencies identified at other plants, PG&E management formed a Configuration Management Task Force (Ref. PG&E letters to NRC, DCL-88-236 and DCL-89-099, Refs. 5.1, 5.2). The Configuration Management Task Force compared PG&E's configuration management practices with others in the industry. The task force concluded that although the DCPP design bases were retrievable and could be effectively used in the design process, the design bases were not in the format recommended by the industry. In addition, although the design bases were available and adequate for use by engineering staff, documentation was not easily accessible or understood by plant personnel. As a result of the task force review and recommendations, PG&E implemented a Configuration Management Program (CMP).

To address the design basis format concerns, PG&E implemented a DCM enhancement program as part of the CMP. As a result of this program, the original DCMs were revised into a new format that provided a more complete compilation of the various design bases. In addition, references to the sources of the design basis information were clarified.

Prior to this effort, DCMs had existed for some systems, structures and topical areas. However, these documents were in an abbreviated format that did not facilitate an understanding of the design bases. The enhanced DCM effort intended to make the information easily accessible, while at the same time provide a better understanding of where and how that information was determined. The enhanced DCMs were developed by a task force led by Engineering, with review and comment provided by other plant disciplines and groups.

The DCM enhancement effort started in 1989 and continued through 1994, when the program was officially declared complete. The original program was aggressive and identified the preparation of a total of 111 enhanced DCMs. The scope was later reduced to 89 enhanced DCMs, based on the remaining items being nonsafety-related and an evaluation of the expected benefit in relation to the required effort. The 89 DCMs that were written included all safety-related and important-to-safety systems, structures and topics. Various nonsafety-related systems, structures, and topics that had the potential to challenge safety-related systems, structures and components, were also included, as were others that PG&E management considered to be of particular importance. Lists of the enhanced DCMs for both safety-related and nonsafety-related systems, structures, and topics are provided below:

DCMs for Safety-Related Systems and Topics

DCM NUMBER	TITLE
DCM S-3B	Auxiliary Feedwater System
DCM S-7	Reactor Coolant System
DCM S-8	Chemical and Volume Control System
DCM S-9	Safety Injection System
DCM S-10	Residual Heat Removal System
DCM S-12	Containment Spray System
DCM S-13	Spent Fuel Pool Cooling System
DCM S-14	Component Cooling Water System
DCM S-16	Makeup Water System
DCM S-17B	Auxiliary Saltwater System
DCM S-18	Fire Protection System
DCM S-21	Diesel Engine System
DCM S-23A	Containment HVAC System
DCM S-23B	Main Auxiliary Building Heating and Ventilating System
DCM S-23C	Miscellaneous Auxiliary Building HVAC Systems
DCM S-23D	Fuel Handling Building Heating and Ventilation System
DCM S-23E	Turbine Building HVAC System
DCM S-23F	Control Room HVAC System
DCM S-23G	Intake Structure Ventilation System
DCM S-25B	Backup Air/Nitrogen Supply Systems
DCM S-37	Nuclear Instrumentation System
DCM S-38A	Plant Protection System
DCM S-39	Radiation Monitoring System
DCM S-42A	Fuel Handling System
DCM S-42B	Fuel Handling Cranes and Storage Racks
DCM S-63	4160 Volt System
DCM S-64	480 Volt Electrical System
DCM S-65	120 Volt Alternating Current System
DCM S-67	125V/250V Volt Direct Current System
DCM T-1A	Containment Structure - Exterior
DCM T-1B	Containment Structure - Interior
DCM T-1C	Containment Structure - Annulus
DCM T-1D	Containment Structure - Liner
DCM T-1E	Containment Pipeway Structure
DCM T-1F	Containment Plant Vent
DCM T-2	Auxiliary Building

DCM NUMBER	TITLE
DCM T-3	Structural Design of the Fuel Handling Building Steel Superstructure
DCM T-6	Seismic Analysis of Class 1 Structures
DCM T-7	Structural Design of Design Class I HVAC Ducts and Duct Supports
DCM T-8	Structural Design of Electrical Raceways and Class 1E Supports
DCM T-9	Wind, Tornado and Tsunami
DCM T-10	Seismic Qualification of Equipment
DCM T-11	Control of Heavy Loads
DCM T-12	Pipe Break (HELB/MELB) Flooding and Missiles
DCM T-13	Appendix R Fire Protection
DCM T-14	Seismically Induced System Interaction
DCM T-15	Radiation Protection
DCM T-16	Containment Function
DCM T-18	Electrical System Protection
DCM T-19	Electrical Separation and Isolation
DCM T-20	Environmental Qualification
DCM T-22	Electrical Cable, Termination and Raceway
DCM T-23	Miscellaneous Electrical Devices
DCM T-24	Design Criteria for DCPP Instrumentation and Controls
DCM T-25	Pipe Stress Analysis
DCM T-26	Pipe Support Analysis
DCM T-28	Design Class I Outdoor Water Storage Tanks
DCM T-29	Pipe Rupture Restraints
DCM T-31	Safety-Related Masonry Walls
DCM T-32	Containment Coatings (Class 1)
DCM T-33	Remote Shutdown Criteria
DCM T-38	Criteria for the Design of Instrument Tubing and Supports
DCM T-42	Station Blackout

DCMs for Nonsafety-Related Systems and Topics

DCM NUMBER	TITLE
DCM S-2A	Condensate System
DCM S-2B	Condensate Polishing System
DCM S-3A	Main Feedwater System
DCM S-3C	Main Feedwater and Steam Dump Control System
DCM S-4	Turbine Steam Supply System
DCM S-11	Nuclear Steam Supply Sample System
DCM S-19	Liquid Radwaste System
DCM S-24	Gaseous Radwaste System
DCM S-25A	Compressed Air System
DCM S-38B	ATWS Mitigation System Actuation Circuitry (AMSAC)
DCM S-43A	Plant Process Computer
DCM S-43B	Annunciator System
DCM S-52	Emergency Response Facility Data System
DCM S-61A	Main Generator and 25 kV System
DCM S-61B	500 kV and 230 kV Systems
DCM S-62	12 kV System
DCM S-68	Lighting, Heat Trace and Cathodic Protection Systems
DCM S-78	Solid Radwaste System
DCM S-98	Penetration Seals
DCM T-4	Structural Design of the Turbine Building
DCM T-5	Structural Design of the Intake Structure
DCM T-17	Long Term Cooling Water
DCM T-21	Grounding
DCM T-36	Secondary Chemistry Sampling System and the Secondary Process Control Room
DCM T-39	Maintenance Shop Expansion
DCM T-40	Toxics and Explosive Materials

The DCM Enhancement Process

In addition to the format and editorial changes, PG&E's DCM enhancement activities included the review of associated license requirements: commitments, codes and standards; correspondence with the NSSS and other key suppliers; and analyses and calculations. This process specifically included a review of the FSAR Update and the Technical Specifications to ensure compatibility between these documents and the design bases.

As a part of the DCM enhancement process, missing information and information needed to improve the understanding of the design bases were identified as open items. The open items were documented and addressed through PG&E's problem resolution process. Each open item was evaluated for its safety significance and, if determined to be significant, was promptly addressed. In addition, open items that met the requirements of 10 CFR 50.72 and 50.73 were reported to the NRC.

Open items that were considered to be safety-significant were required to be addressed prior to issuance of the associated DCM. Only those open items judged to be nonsafety-significant were allowed to be carried as an open item in the DCMs. Through this process, approximately 1,300 open items were identified in the initial issue of the enhanced DCMs. The exact number of original open items is not available because they were not tracked directly as a part of the DCM process. The number of significant open items also was not tracked. However, the number of open items that resulted in the identification of quality problems was relatively low. PG&E has addressed and closed the vast majority of the original open items; approximately 130 low priority items remain to be closed.

Verification of Transfer of Design Bases

To verify the accurate transfer of the design bases to the maintenance, testing, and operation procedures, and to ensure that the DCMs met the requirements of the end users, various groups including Operations, Maintenance, and System Engineering, were requested to review the DCMs. These reviews were specifically targeted toward ensuring the incorporation of the design bases, and their verification, into the various maintenance, surveillance, and operating procedures and programs. These activities are described in Section (b), Design Basis Translation to Operating, Maintenance, and Testing Procedures.

In addition, to ensure that Operations personnel were properly trained in the current configuration and design basis requirements, the enhanced DCMs were reviewed by the Training department and training materials were modified as required to reflect the design bases.

To further validate the quality and accuracy of the enhanced DCMs, various DCMs were reviewed as a part of PG&E's audit program and the NRC's inspection program. The DCMs

were found to be of substantial value as a single, concise source of design basis information. In addition, the SSFARs that were conducted included assessments of completeness and accuracy of the DCMs. Each of the SSFARs noted minor discrepancies in the DCMs. However, overall the DCMs were determined to be complete and accurate.

Revision Process for the DCMs

To ensure that future changes to the plant are appropriately controlled, the revision process for DCMs is proceduralized and contains the same controls as the design change process. Each DCM has an owner, who is responsible for coordinating changes to the DCM. DCM revisions must be tracked in PIMS. Each revision must be reviewed pursuant to the LBIE procedure and, if required, a 10 CFR 50.59 review must be performed. If a 10 CFR 50.59 review is required, the revision can only proceed as a design change package requiring full coordination. For DCM revisions, coordination is required with NPG groups affected, including Engineering, Construction, Maintenance, Testing and Operations.

In addition, revisions to design documents or to maintenance, testing or operating procedures require review of the associated DCMs. This requirement also is proceduralized.

The 1996 Engineering Self-Assessment Team found a number of DCMs that were not readily usable, because of numerous pending changes. As a result, the process was enhanced to make better use of PG&E's Electronic Document Management System (EDMS), as described below, and the DCMs were updated before the end of 1996 to incorporate pending changes.

To ensure easy access to the current version and pending revisions to DCMs, these documents now are provided and controlled in EDMS. This computerized system provides a mechanism for the review of past and potential future revisions. This electronic system has been developed with security measures to allow access to users for viewing and copying the DCMs, but does not allow unauthorized revision or manipulation. Authorized and approved revisions are incorporated promptly to ensure that a user is viewing the current version.

Summary Conclusions

The DCM enhancement program has increased the overall knowledge of the design bases of the plant, has confirmed compliance with DCPP's design bases and has provided design basis information in a format that can be effectively accessed and used by NPG personnel. Thus the program has helped ensure that compliance with the design bases is maintained in DCPP design, maintenance, testing and operation. This program provides for ongoing updates and maintenance of the DCMs. This program, along with the various design change vehicles and commitment tracking systems, also ensures that the design bases, and changes to the design bases, are well-

documented and controlled, and communicated to the appropriate personnel and reflected in the appropriate documents.

CONCLUSIONS AND FUTURE ACTIONS

As discussed above, PG&E believes that it began DCPP operation with a solid design basis foundation, rebaselined its design bases following initial licensing, and further improved its design control processes and documentation during the Configuration Management Program. PG&E has maintained control over its design bases through effective processes for design changes, procedure changes, FSAR changes, and 10 CFR 50.59 safety evaluations. Numerous internal audits and self-assessments have been performed and provide added assurance that the design change and configuration management processes have been effective. When problems were identified, they have been effectively addressed by the problem resolution process. Collectively, the problems found have been few. Some have been significant but none have resulted in a system being incapable of performing its intended safety function. PG&E therefore believes that there is reasonable assurance that DCPP currently conforms to its design bases and that the processes are in place to ensure that it will continue to do so in the future.

Notwithstanding this conclusion, PG&E believes that it can achieve a higher level of certainty and performance in ensuring that DCPP continues to conform with its design and licensing bases by taking some additional actions to improve its programs.

Enhanced Configuration Management Training

PG&E plans to implement further training in areas of configuration management, 10 CFR 50.59 evaluations, and FSAR Update processes. This training will be provided to the Engineering organization and to appropriate members of the Operations and Maintenance organizations. PG&E believes that this training will improve the consistency of operation within the design bases and bring its 10 CFR 50.59 evaluations into alignment with current NRC expectations.

Bases Enhancement

PG&E plans to perform some additional review of the FSAR Update and DCMs as follows.

Final Safety Analysis Report Update

PG&E performed a review of the FSAR Update against the design and operation of the plant in early 1996, and identified a number of inconsistent or inaccurate statements. Most of these were rectified in the November 1996 revision of the FSAR Update, and PG&E has committed to submit a supplemental FSAR Update in April 1997 to correct the remainder. This supplement will be in addition to the routine revisions required by 10 CFR 50.71(e).

A follow-up review of the FSAR Update will be performed to further clarify details and enhance accuracy. The follow-up review will include topical areas of the FSAR Update along the lines of that initiated by the Operations department in December 1996. Other topical areas being considered include Maintenance and Testing. The follow-up review will focus on statements in the FSAR Update to ensure that the licensing bases are accurately reflected consistent with the design bases. Some effort will also be focused on how to clearly identify that information in the FSAR Update that is truly important for clarity of use and update. The results of this review will be incorporated into the next scheduled revision of the FSAR Update as required by 10 CFR 50.71(e). PG&E will provide a separate letter to the NRC detailing its FSAR review effort. This effort will be completed in time for PG&E's next formal FSAR Update, currently scheduled for August 1998.

PG&E also plans to implement the NEI Industry Licensing Basis initiative, and will use the results of the effort to identify the extent of the follow-up review discussed above. The NEI initiative was adopted by some licensees in late 1996 as an approach to address licensing basis issues in plant operation. In implementing the initiative, PG&E will:

(1) Conduct an assessment of the programs currently in use at DCPP to ensure that the plant is operated in conformance with its licensing bases using NEI 96-05, "Guidelines for Assessing Programs for Maintaining the Licensing Basis," or other approaches that provide an equivalent scope of review

(2) Assess the accuracy of the FSAR Update descriptions for two safety-related systems and two nonsafety-related systems at DCPP determined to be risk-significant pursuant to the NRC's Maintenance Rule

(3) Ensure that identified nonconforming or degraded conditions at DCPP are captured on a tracking system and resolved in a timely manner

PG&E plans to begin implementing the NEI initiative in mid-1997, and expects to complete this activity by the end of 1997.

Design Criteria Memoranda Review

In conjunction with the FSAR Update reviews and the NEI initiative, PG&E will also conduct some additional reviews of the DCPP operation, testing, and maintenance procedures for consistency with appropriate DCMs. As mentioned in Section (b), Design Basis Translation to Operating, Maintenance, and Testing Procedures, this will include the DCM reviews of maintenance and testing procedures that are scheduled to be completed during the first half of 1997. PG&E will also perform some additional reviews of DCMs for their consistency with operating procedures. PG&E will complete the reviews in the context of current plant practices to confirm that they are consistent with the design bases. The scope and schedule of this effort will be dependent on initial findings during the review process.

QA Audits and Assessments

PG&E believes that "vertical-slice" assessments, such as SSFARs and SSOMIs, are an effective means of assessing design basis control programs. The SSOMIs and SSFARs have been effective in identifying problem areas and, PG&E believes, have resulted in significant improvements to the processes for design basis conformance. PG&E will continue to perform SSOMIs for outages. PG&E plans to perform additional assessments as part of its NEI initiative implementation previously described, and will use the results of these assessments to decide whether future full-scale SSFARs or other vertical-slice assessments are needed.

APPENDIX A - REFERENCES

1. Program Directives and Interdepartmental Administrative Procedures

1.1	AD1	Administrative Controls Program
1.2	AD1.ID1	Format, Content, and Style of Procedures
1.3	AD1.ID2	Review Level "A" Procedure Review, Approval and Notification of Changes
1.4	AD1.ID3	Review Level "B" Procedure Review, Approval and Notification of Changes
1.5	AD1.ID7	Editorial Corrections and On-The-Spot Changes
1.6	AD3	Document Control
1.7	AD3.ID2	Distribution, Control, and Use of Design Drawings, Field Drawings and Operating Valve Identification Diagrams
1.8		Not used
1.9	AD5	Inspections
1.10	AD7	Work Planning and Management
1.11		Not used
1.12	AD9	Procurement Control
1.13	AD10	Records
1.14		Not used
1.15	AD13	Test Control
1.16	CF1	Configuration Management
1.17	CF2	Computer Hardware, Software, and Database Control
1.18	CF2.ID7	Component Database Program - Change Process
1.19	CF3	Design Control
1.20	CF3.ID2	Design Criteria Memoranda
1.21	CF3.ID3	Environmental Qualification Program
1.22	CF3.ID4	Design Calculations
1.23	CF3.ID5	Drawing Preparation and Approval
1.24	CF3.ID6	Field Correction Transmittal Processing
1.25	CF3.ID8	Maintenance Modification Package Development
1.26	CF3.ID9	Design Change Package Development
1.27	CF3.ID10	Maintenance Modification Action Requests
1.28	CF3.ID11	Seismic Configuration Control Program
1.29	CF3.ID12	Graded Quality Program for Reg. Guide 1.97 Category 2 and 3 Instrumentation
1.30	CF3.ID13	Replacement or New Part Evaluation (RPE)
1.31	CF3.ID15	Development and Independent Verification of Calculations or Computer Programs
1.32	CF3.ID16	Specifications
1.33	CF3.ID17	Design Documents Prepared by External Contractors

1.34	CF4	Modification Control
1.35	CF4.ID1	Design Change Requests and Design Change Vehicles
1.36	CF4.ID3	Design Change Package Implementation
1.37	CF4.ID4	Field Change Process
1.38	CF4.ID7	Temporary Modifications - Plant Jumpers and M&TE
1.39	CF4.ID8	Temporary Attachments
1.40		Not used
1.41	CF5	Materials Control
1.42	CF6	Setpoint Control
1.43	CF6.ID2	Setpoint Change Control Program
1.44	CF7	Control and Use of Supplier Information
1.45	CF7.ID1	Control and Distribution of Vendor Manuals Important to Plant Safety and Reliability
1.46	CY1	Chemistry/Radiochemistry
1.47		Not used
1.48	MA1	Maintenance
1.49	MA1.ID7	Control of Plant Floor Loading
1.50	MA1.ID8	Control of Temporary Rigging from Plant Equipment, Piping and Structural Members
1.51	MA1.ID11	Rigging and Load Handling
1.52	MA1.ID14	Plant Crane Operating Restrictions
1.53	OM4	Nuclear Oversight Program
1.54	OM5	Quality Assurance Program
1.55	OM7	Problem Resolution
1.56	OM7.ID1	Problem Identification and Resolution - Action Requests
1.57	OM7.ID3	Nonconformance Report (NCR) and Technical Review Group (TRG)
1.58		Not used
1.59		Not used
1.60	OM12	Shift Turnover
1.61	OP1	Operations Management
1.62	OP2	Tagging Programs
1.63	RP1	Radiation Protection
1.64		Not used
1.65	RP1.ID2	Use and Control of Temporary Radiation Shielding
1.66		Not used
1.67	TQ1	Personnel Training and Qualification
1.68	TQ1.ID10	Procedure Sponsor, Reviewer, and Approver Qualifications
1.69	TQ2	Accredited Training Programs
1.70		Not used
1.71	TS2	Procurement of Nuclear Fuel and Related Goods and Services
1.72	TS3	Safety Analyses and Licensing Basis Impact Evaluations
1.73	TS3.ID1	Coordination of Safety-Related Analytical Work Performed by Vendors
1.74	TS3.ID2	Licensing Basis Impact Evaluations
1.75	TS5	Engineering Support Functions

1.76		Not used
1.77	XI3	Licensing Basis Documents
1.78	XI3.ID1	Technical Specification Change Process
1.79	XI3.ID2	DCPP Final Safety Analysis Report (FSAR) Update Revision and Maintenance
1.80	XI4	Commitment Tracking and Control
1.81	XI4.ID2	Commitment Change Process
1.82		Not used
1.83		Not used
1.84	AD13.ID1	Conduct of Plant and Equipment Tests
1.85	AD13.DC1	Control of the Surveillance Testing Program
1.86	AD13.ID2	Post Modification Testing
1.87	AD13.ID4	Post Maintenance Testing
1.88	AD13.ID5	Inservice Testing Program
1.89	TS5.ID1	System Engineering Program
1.90	AD5.ID2	Inservice Inspection Program
1.91	AD9.ID11	Supplier Audits and Surveys
1.92	CF7.ID2	Distribution of 10 CFR 21 Notifications Received from Outside Entities
1.93		Not used
1.94	AD9.ID7	Receipt Inspection and Acceptance Testing
1.95	AD4.ID8	Identification and Resolution of Loose, Missing or Damaged Fasteners
1.96	AD4.ID2	Plant Leakage Evaluation
1.97	MA2.ID2	Performance Monitoring Equipment Calibration and Usage Control
1.98	OP1.ID1	Readiness for Restart Program
1.99	OM4.ID11	Balance of Plant Reliability Program
1.100	OM4.ID12	Performance-Based Self-Evaluations
1.101	OM4.ID3	Assessment of Industry Operating Experience
1.102	XI1.ID1	Regulatory Correspondence Processing
1.103	OM3.ID3	Employee Concerns Program (Quality Hotline)
1.104	OM7.ID7	Integrated Problem Response Team
1.105	OM7.ID4	Root Cause Analysis
1.106	OM7.ID9	Human Performance Enhancement System (HPES)
1.107	OM7.ID2	Quality Evaluations
1.108	OM4.ID13	Internal Auditing
1.109	OM7.ID8	Operability Evaluation
1.110	XI1.ID2	Regulatory Reporting Requirements and Reporting Process
1.111	OM7.ID10	Quality Trend Analysis Program
1.112	CF3.NE1	Classification of Structures, Systems, and Components
1.113	AD7.DC5	Control Doors Important to Safety
1.114	OP1.DC16	Equipment Control Guidelines
1.115	M-1	Fire Hazards Appendix R Evaluations (FHAREs) - Engineering, Mechanical Implementing Procedure
1.116		Not used
1.117	OM7.ID12	Prompt Operability Assessment

1.118	OM7.ID5	Issues Needing Validation to Determine Impact on Operability (INVDIO)
1.119	OP1.DC17	Technical Specifications
1.120		Not used
1.121	CF7.ID3	Processing of Information Provided by Suppliers
1.122	AD9.ID1	Procurement of Items and Related Services
1.123	OP2.ID1	Clearances and Administrative Tag-Outs
1.124	OP2.ID2	DCPP Tagging Requirements
1.125	AD5.ID1	Independent Inspection Program
1.126	TQ2.ID4	Training Program Implementation
1.127	AD1.DC1	DCPP Procedures
1.128	OP1.DC12	Conduct of Routine Operations
1.129		Not used
1.130	OM4.ID2	Plant Staff Review Committee (PSRC)
1.131	AD4.ID3	SISIP Review of Housekeeping Activities
1.132	OP1.DC3	Nuclear Operator Routine Plant Equipment Inspections
1.133	OP1.DC10	General Authorities and Responsibilities of Operating Shift Personnel
1.134		Not used
1.135	CF6.ID1	Setpoint Control Program
1.136	AD7.ID1	Use of PIMS Work Order Module
1.137	AD7.ID5	Scaffold Material Structures
1.138	AD2.ID1	Procedure Use and Adherence
1.139	TS2.ID1	Nuclear Fuel Fabrication and Analysis Services
1.140	TQ2.ID10	Engineering Support Personnel Training Program
1.141	MA1.ID1	Program Plan for Compliance with Generic Letter 89-10 (MOV Surveillance and Testing)
1.142	PRC-10	Preoperational and Startup Testing Procedure (04/24/73)
1.143	XI3.ID3	Technical Specifications Interpretation
1.144	OP1.DC31	Dissemination of Operations Information
1.145	CF7.ID4	Processing of Supplier Engineering Documents
1.146	AD8.DC55	Outage Safety Scheduling

2. <u>Audits and Self-Assessments</u>

2.1 Audit 86259T, ASW System Audit (10/14/87)
2.2 Audit 87153T, Control Room Ventilation System Audit (10/26/87)
2.3 Audit 87247T, Diesel Generator System Audit (02/19/88)
2.4 Audit 88803T, 4160 kV System Audit (03/31/88)
2.5 1R2 SSOMI Surveillance (08/08/88)
2.6 2R2 SSOMI Surveillance (04/12/89)
2.7 Audit 89800T, Electrical System SSFAR (05/31/89)
2.8 Audit 89808T, AFW SSFAR, Safety System Functional Audit and Review (11/17/89)
2.9 1R3 SSOMI Surveillance (03/14/90)
2.10 Audit 90811T, CCW SSFAR, Safety System Functional Audit and Review (11/02/90)

2.11 2R3 SSOMI Surveillance (12/12/90)
2.12 Audit 90830T, 1R4/2R4, SSOMI, Design Assessment (01/18/91)
2.13 Audit 91001I, Comprehensive Procurement Audit (03/22/91)
2.14 Audit 91007I, 1R4 SSOMI, Installation (05/10/91)
2.15 Audit 91028I, 2R4 SSOMI, Installation (11/26/91)
2.16 Audit 92001I, SSFAR Safety Injection (SI), Safety System Functional Audit and Review (05/15/92)
2.17 Audit 92028I, 1R5 Design SSOMI (08/13/92)
2.18 Audit 92036I, 1R5 SSOMI, Installation (12/18/92)
2.19 Not used
2.20 Audit 93001I, Comprehensive Procurement Program (04/20/93)
2.21 Not used
2.22 Audit 93006I, 2R5 SSOMI (06/04/93)
2.23 Audit 93014I, Environmental Qualification (07/28/93)
2.24 Audit 93015I, SSFAR RHR, Safety System Functional Audit & Review (11/05/93)
2.25 Audit 93047I, 1R6 SSOMI, Design Assessment (02/11/94)
2.26 Audit 95012I, Procurement Audit (05/26/95)
2.27 Audit 94015I, 1R6 SSOMI, Installation Assessment (07/15/94)
2.28 Audit 94016I, GL 89-10 Program Audit (07/15/94)
2.29 Audit 94023I, Post Fire Safe Shutdown (08/31/94)
2.30 Audit 95014I, 1R7 Safety System Outage Modification Inspection; 1R7 SSOMI, Design Assessment (10/16/95)
2.31 Audit 95032I, 1R7 Technical Support Outage Assessment (01/09/96)
2.32 Not used
2.33 Audit 960890033, 2R7 Technical Support Outage Assessment (TSOA) (06/28/96)
2.34 Not used
2.35 Joint Utility Management Audit 11/06/89 - 11/10/89
2.36 Joint Utility Management Audit 10/21/91 - 10/25/91
2.37 Joint Utility Management Audit 11/01/93 - 11/08/93
2.38 Joint Utility Management Audit 11/28/95 - 12/05/95
2.39 Surveillance QP&A-93-0031, Generic Letter 89-13, Service Water System Performance (07/28/93)
2.40 PG&E Engineering Self-Assessment, dated 03/28/96
2.41 Not used
2.42 Not used
2.43 Audit 95018I, Corrective Action Audit (8/21/95)
2.44 Audit 94035I, Corrective Action Audit (1/20/95)
2.45 2R6 Technical Support Outage Assessment (TSOA) (12/20/94)
2.46 Audit 960570014, Corrective Action Audit (05/17/96)
2.47 Not used
2.48 QA Audit 962700005, 4th Quarter, 1996 Operations

3. Regulatory Documents

3.1 Not used
3.2 Units 1 and 2 Diablo Canyon Power Plant Final Safety Analysis Report Update.
3.3 Units 1 and 2 Diablo Canyon Power Plant Technical Specifications.
3.4 NUREG - 0675, "Safety Evaluation Report Related to the Operation of Diablo Canyon Nuclear Power Plant, Units 1 and 2," prepared by the U.S. Atomic Energy Commission, dated October 16, 1974, with Supplements.
3.5 NRC Inspection Report 50-275/91-11 and 50-323/91-11
3.6 NRC Inspection Report 50-275/93-32 and 50-323/93-32
3.7 NRC Inspection Report 50-275/91-07 and 50-323/91-07
3.8 NRC Inspection Report 50-275/92-22 and 50-323/92-22
3.9 NRC Inspection Report 50-275/96-99 and 50-323/96-99
3.10 Not used
3.11 NRC Inspection Report 50-275/91-10 and 50-323/91-10
3.12 NRC Inspection Report 50-275/96-13 and 50-323/96-13
3.13 Not used
3.14 NRC Inspection Report 50-275/96-16 and 50-323/96-16
3.15 NRC Inspection Report 50-275/88-15 and 50-323/88-14
3.16 NRC Inspection Report 50-275/92-30 and 50-323/92-30
3.17 NRC Inspection Report 50-275/92-31 and 50-323/92-31
3.18 Not used
3.19 NRC Generic Letter 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability"
3.20 NRC Inspection Report 50-275/90-13 and 50-323/90-13
3.21 NRC Inspection Report 50-275/93-16 and 50-323/93-16
3.22 NRC Inspection Report 50-275/94-29 and 50-323/94-29
3.23 NRC Inspection Report 50-275/96-02 and 50-323/96-02
3.24 NRC Inspection Report 50-275/96-21 and 50-323/96-21
3.25 NRC Inspection Report 50-275/93-26 and 50-323/93-26
3.26 NRC Inspection Report 50-275/90-30 and 50-323/90-30
3.27 NRC Inspection Report 50-275/94-24 and 50-323/94-24
3.28 NRC Inspection Report 50-275/96-09 and 50-323/96-09
3.29 NRC Inspection Report 50-275/94-08 and 50-323/94-08
3.30 NRC Inspection Report 50-275/93-34 and 50-323/93-34
3.31 NRC Inspection Report 50-275/94-28 and 50-323/94-28
3.32 Not used
3.33 NRC Inspection Report 50-275/90-23 and 50-323/90-23
3.34 NRC Inspection Report 50-275/90-18 and 50-323/90-18
3.35 NRC Inspection Report 50-275/90-01 and 50-323/90-01
3.36 NRC Inspection Report 50-275/91-40 and 50-323/91-40
3.37 NRC Inspection Report 50-275/96-12 and 50-323/96-12
3.38 NRC Inspection Report 50-275/93-24 and 50-323/93-24

3.39 Amendment No. 117 to Facility Operating License No. DPR-80 and Amendment No. 115 to Facility Operating License No. DPR-82, for Diablo Canyon Power Plant, Units 1 and 2
3.40 NRC Inspection Report 50-275/91-19 and 50-323/91-19
3.41 NRC Inspection Report 50-275/89-32 and 50-323/89-32
3.42 NRC Inspection Report 50-275/92-34 and 50-323/92-34
3.43 NRC Inspection Report 50-275/94-99 and 50-323/94-99
3.44 NRC Inspection Report 50-275/94-03 and 50-323/94-03
3.45 NRC Inspection Report 50-275/95-06 and 50-323/95-06
3.46 NRC Inspection Report 50-275/96-20 and 50-323/96-20
3.47 NRC Inspection Report 50-275/93-11 and 50-323/93-11
3.48 NRC Inspection Report 50-275/93-14 and 50-323/93-14
3.49 NRC Inspection Report 50-275/96-06 and 50-323/96-06

4. Special Programs

4.1 Not used
4.2 "Independent Design Verification Program - Diablo Canyon Nuclear Power Plant - Unit 1," prepared by Teledyne Engineering Services, Dated October 10, 1983.
4.3 "Phase II Final Report - Design Verification Program - Diablo Canyon Power Plant," prepared by PG&E, issued 1982.
4.4 Exhibit 1024, Testimony of Darrell G. Eisenhut on the NRC's View of the Design Verification Program
4.5 Design Change Process Initiative Project (DCPIP)

5. Correspondence and Miscellaneous Documentation

5.1 PG&E Letter No. DCL-88-236, "Reply to Notice of Violation in NRC Inspection Report Nos. 50-275/88-15 and 50-323/88-14," October 5, 1988
5.2 PG&E Letter No. DCL-89-099, "Enhancements to PG&E's Configuration Management Program," April 19, 1989
5.3 PG&E Letter No. DCL 90-027, "Response to Generic Letter 89-13," January 26, 1990
5.4 PG&E Letter No. DCL 91-286, "Supplemental Response to Generic Letter 89-13," November 25, 1991
5.5 PG&E Letter No. DCL 94-262, "Closure Response to NRC Generic Letter 89-10," November 28, 1994
5.6 Not used
5.7 Not used
5.8 Not used
5.9 PG&E Letter DCL-89-10 (04/20/89), "Reply to NRC Inspection Report 89-01"
5.10 PG&E Internal Correspondence, Chron # 132610
5.11 PG&E Internal Correspondence, Chron # 146444
5.12 Not used
5.13 Not used

5.14 PG&E Action Request AR A0131260, “Conduct a Configuration Management Program”
5.15 PG&E Action Request AR A0311537, “Operating Procedure Reviews not Completed as Scheduled”
5.16 NCR DC0-89-TN-081, “FSAR/Plant Procedure Review”
5.17 NCR DC0-91-EN-N005, “Post-Accident Monitoring”
5.18 Operability Evaluation OE 91-13, “Operability of Non-Conforming Regulatory Guide 1.97 Post-Accident Monitoring Instrumentation”
5.19 Not used
5.20 NCR N0001951, “Corrective Action Program Effectiveness”
5.21 PG&E Letter No. DCL 96-084, “DCPP Engineering Self-Assessment Final Report,” 03/28/96
5.22 PG&E Letter No. DCL 96-190, “Final Report of the Issue Closure Team, DCPP Units 1 and 2,” 09/17/96
5.23 Nuclear Safety Analysis Center Report NSAC-125, “Guidelines for 10 CFR 50.29 Safety Evaluations,” June 1989
5.24 NCR DC0-92-EN-N010, “Control Circuit Voltage Drop”
5.25 NCR N0002008, “Improvements to the 50.59 Evaluation Process”
5.26 NCR N0001977, “Flashing at the CFCUs”
5.27 NCR N0001911, “230 kV System Inoperable Due to Morro Bay Line Outage”
5.28 NCR N0001950, “JUMA Audit Finding on NQS Performance”
5.29 NUMARC 90-12, Design Basis Program Guidelines (06/29/90)
5.30 Not used
5.31 Charter, Daily AR Review Team (DART)
5.32 NCR DC0-90-TN-N060, “Containment Fan Cooler Flow”
5.33 AR A0394406, “Evaluate STP P-AFW-11 Maximum Turbine Speed vs. SGTR Analysis”
5.34 AR A0395097, “Investigate Recirculation Delta P Criteria Contained in “A” Test”
5.35 QE Q0011838, “Design Basis STP Acceptance Criteria Revised Without DCP/DCN”
5.36 PG&E Letter DCL-90-204 (08/13/90), “Reply to Notice of Violation in NRC Inspection Report 90-13”
5.37 PG&E Letter DCL 91-207 (08/19/91), “Reply to Notice of Violation in NRC Inspection Report 91-07”
5.38 PG&E Letter DCL 92-233 (10/22/92), “Reply to Notice of Violation in NRC Inspection Report 92-22”
5.39 PG&E Letter DCL 93-214 (08/30/93), “Reply to Notice of Violation in NRC Inspection Report 93-16”
5.40 PG&E Letter DCL 95-008 (01/17/95), “Reply to Notice of Violation in NRC Inspection Report 94-29”
5.41 PG&E Letter DCL 96-104 (05/10/96), “Reply to Notice of Violation in NRC Inspection Report 96-02”
5.42 PG&E Letter DCL 93-267 (11/24/93), “Reply to Notice of Violation in NRC Inspection Report 93-24”
5.43 PG&E Letter DCL 96-161 (07/19/96), “Reply to Notice of Violation in NRC Inspection Report 96-09”

5.44 PG&E Letter DCL 91-072 (04/01/91), "Reply to Notice of Deviation in Inspection Report 90-30"
5.45 NCR DC0-92-NS-N007, "ECCS Issues"
5.46 NCR DC0-94-EN-N018, "CCW/Throttling to CCP Coolers"
5.47 NCR N0001784, "Issues Related to NRC Audit of ASW System"
5.48 QE Q0010785, "Failure to Request POA - Degraded Blowout Panels"
5.49 AR A0357141, "AFW Pump 2-1 Does not Meet the Full Flow Acceptance Criteria"
5.50 QE Q0011880, "Usability of the PIMS Component Database
5.51 NCR N0001735, "CCW Heat Exchanger Tube Fretting/Corrosion"
5.52 PG&E letter DCL 94-277 (12/09/94), "Reply to Notice of Violation in NRC Inspection Report 94-28"
5.53 PG&E letter DCL 94-174 (08/05/94), "Reply to Notice of Violation in NRC Inspection Report 94-08"
5.54 PG&E letter DCL 96-167 (08/09/96), "Reply to Notices of Violation and Notice of Deviation in NRC Inspection Report 96-12"
5.55 AR A0350965, "Breaker PY-1118 Found Open on NRC Walkdown"
5.56 NCR DC1-91-EN-N016, "Check Valve RHR-1-8742B"
5.57 PG&E letter DCL 94-026 (02/04/94), "Reply to Notice of Violation in NRC Inspection Report 93-32"
5.58 Not used
5.59 Not used
5.60 Not used
5.61 Not used
5.62 Not used
5.63 NCR N0002003, "EOP E-1.3 Cold Leg Recirculation Transfer Time"
5.64 NCR N0001884, "HELB Interaction with SSPS"
5.65 DCPP Q-List

APPENDIX B - PROGRAM DIRECTIVES RELATED TO DESIGN BASES AND CONFIGURATION CONTROL

Program Directive	Description of Role
AD1- Administrative Controls Program (Ref. 1.1)	• Establishes the hierarchy and provides for the control of procedures, as well as establishing the requirement for departments to prepare IDAPs and DLAPs to address certain topics
AD3- Document Control (Ref. 1.6)	• Addresses the proper control of documents that define the design, communicate design basis requirements, and control activities that can affect physical compliance with design basis requirements
AD5- Inspections (Ref. 1.9)	• Provides for installation, surveillance and Quality Control inspections to verify compliance of structures, systems, and components to design basis requirements identified in design output documents
AD7- Work Planning & Management (Ref. 1.10)	• Provides for the integrated control of work activities affecting structures, systems, and components to include consideration of design bases in plant evolutions and during plant work
AD9- Procurement Control (Ref. 1.12)	• Provides for proper procurement of materials, parts, components and services consistent with design basis requirements
AD10- Records (Ref. 1.13)	• Provides for the retention, control, processing, and storage of records relating to configuration
AD13- Test Control (Ref. 1.15)	• Provides for the definition and control of safety- and quality-related tests that confirm performance consistent with the design bases
CF1- Configuration Management (Ref. 1.16)	• Provides the global view of configuration management
CF2- Computer Hardware, Software, & Database Control (Ref. 1.17)	• Provides for controlling computer hardware, software, and databases consistent with the design bases
CF3- Design Control (Ref. 1.19)	• Addresses the establishment, maintenance, and documentation of design basis requirements, the incorporation of these requirements in design output documents, and the communication of this information to all NPG organizations performing activities that must comply with these requirements. This process controls changes to design bases, preparation of design changes in accordance with design bases, and provides testing requirements and acceptance criteria to demonstrate compliance with design basis requirements.

Appendix B - Program Directives

Program Directive	Description of Role
CF4- Modification Control (Ref. 1.34)	• Addresses the identification, evaluation, and implementation of physical and paper changes in a manner that preserves physical configuration of the plant in compliance with design basis requirements. This includes the proper interface with other PDs to ensure the timely update of plant and design basis documents and information systems consistent with configuration changes.
CF5- Materials Control (Ref. 1.41)	• Provides for the identification, proper handling, and issuance of materials, parts and components
CF6- Setpoint Control (Ref. 1.42)	• Provides specific guidance for control of setpoints consistent with design bases
CF7- Control and Use of Supplier Information (Ref. 1.44)	• Provides for control of supplier information to ensure equipment and other vendor information is appropriately considered in design, maintenance, and operation
CY1- Chemistry/ Radiochemistry (Ref. 1.46)	• Addresses control of plant system chemistry/radiochemistry conditions in compliance with design basis requirements
MA1- Maintenance (Ref. 1.48)	• Provides for preventive and corrective maintenance on plant equipment to retain design basis capability with time
OM4- Nuclear Oversight Program (Ref. 1.53)	• Provides for oversight, assessment, and verification activities including Quality Assurance audits and assessments, Plant Staff Review Committee, and Nuclear Safety Oversight Committee
OM5- QA Program (Ref. 1.54)	• Provides for the Quality Assurance program that meets the requirements of 10 CFR 50, Appendix B
OM7- Problem Resolution (Ref. 1.55)	• Addresses equipment Operability Evaluations for the consideration of design basis requirements in the performance of operability determinations
OM12- Shift Turnover (1.60)	• Addresses the effective transfer of knowledge of the as-is operational configuration of the plant to the relieving watch
OP1- Operations Management (Ref. 1.61)	• Provides controls, responsibilities, and policies for safe operation of the plant consistent with the design bases
OP2- Tagging Programs (Ref. 1.62)	• Provides for clearances and tagging of plant equipment to maintain operational configuration consistent with the design bases
TQ1- Personnel Training & Qualification (Ref. 1.67)	• Provides for training and qualification of personnel working in nuclear activities including training on design bases for selected personnel
TQ2- Accredited Training Programs (Ref. 1.69)	• Provides for training accredited by the National Academy for Nuclear Training

Program Directive	Description of Role
TS2- Procurement of Nuclear Fuel & Related Goods & Services (Ref. 1.71)	• Provides for fabrication controls of nuclear fuel and related analytical services, including design and fabrication within the design basis
TS3- Safety Analyses and Licensing Basis Impact Evaluations (Ref. 1.72)	• Addresses the development and maintenance of plant safety analyses as part of the plant design bases and the appropriate evaluation of changes to the plant equipment or its operation to preserve compliance with design basis requirements and regulatory approved programs (e.g., environmental, fire, emergency, and security plans)
TS5- Engineering Support Functions (Ref. 1.75)	• Provides for the system engineering program that coordinates the interface between design and plant operation, including interpretation of and support related to design bases
XI3- Licensing Basis Documents (Ref. 1.77)	• Provides for control and maintenance of licensing basis documents including the Technical Specifications and the FSAR Update (10 CFR 50.71 (e)). It requires incorporation of design basis changes and related information
XI4- Commitment Tracking & Control (Ref. 1.80)	• Provides for management and coordination of commitments to regulatory agencies, including specific one-time commitments relative to the design bases

APPENDIX C - DEFINITIONS

Definitions of key terms that are used in this response are provided below. These are provided for clarification of meanings that may be unique to PG&E or DCPP.

Action Request (AR), Action Evaluation (AE) - An AR is the documentation, by way of the computerized Plant Information Management System (PIMS), through which all NPG personnel identify and track the majority of DCPP activities, including reporting of problems, requesting action, implementing changes, and tracking resolution of problems. An AE is a part of the process in implementing an AR. More specifically, an AE is a request for assistance, by way of PIMS, in the resolution of an AR by an organization participating in the resolution of the AR. There may be more than one AE for an AR.

Component Database (CDB) - The database subsystem in PIMS used to track plant operating and maintenance and certain design data for DCPP equipment at a component level. The CDB also provides information to control and direct activities involving component maintenance.

Configuration Management - An integrated process that identifies existing plant licensing and design requirements and details of the implementation of those requirements, and controls changes to ensure that the plant is configured, maintained, operated, and managed in a manner that is consistent with the design bases and licensing commitments. The configuration management process also ensures that design documents, such as calculations, drawings, procedures, etc., actually reflect the physical installations and operating conditions at DCPP.

Design Basis - That information which identifies the specific functions to be performed by a structure, system, or component of a facility, and the specific values or ranges of values chosen for controlling parameters as reference bounds for design. These values may be (1) restraints derived from generally accepted "state of the art" practices for achieving functional goals, or (2) requirements derived from analysis (based on calculation and/or experiments) of the effects of a postulated accident for which a structure, system, or component must meet its functional goals. [from 10 CFR 50.2]

Implicit in this definition is documentation of the reason why a function must be performed and why a specific value or range of values is necessary as a controlling parameter. Analysis and calculation inputs and outputs that are required to demonstrate compliance to a functional requirement are considered as design bases.

In its October 9, 1996, letter, the NRC stated, "*The design bases of a facility, as so defined, is a subset of the licensing basis and is contained in the Final Safety Analysis*

Report. Information developed to implement the design bases is contained in other documents, some of which are docketed and some of which are retained by the licensee."

Design Change - Any (1) modification to plant structures, systems, or components that may or may not be described in approved Design Criteria Memoranda, specifications, drawings, or supplier documents that alter or could affect various attributes of plant design; (2) new or revised design constraints on operating and maintenance practices, or (3) revision to approved requirements of Design Output Documents (including those prepared by architect/engineers or consultants), design classification, installation specifications, supplier drawings, or engineering specified setpoints and device settings.

Design Change Evaluation (DCE) - That portion of the Design Change Package (DCP) that includes the technical review of the design change. The DCE identifies the design bases and design inputs applicable to the design change and contains a technical review used to determine the full effect of the design change.

Design Change Notice (DCN) - That portion of the DCP, that includes the installation and testing requirements and operating constraints for the Design Change Package, the design drawings list, and sketches. There may be more than one DCN included in a DCP.

Design Change Package (DCP) - A vehicle used to transmit design change projects that cannot be processed using a Maintenance Modification. A DCP is comprised of a DCE and one or more DCNs.

Design Change Vehicle - A document that communicates the specific details of a design change (e.g., Design Change Package, Replacement Part Evaluation, etc.).

Design Criteria Memorandum (DCM) - A document used to identify design bases and other design inputs for a given system or structure. (Other facilities refer to these documents as Design Basis Documents or similar titles.)

Design Output Documents - Drawings, specifications, and other documents defining technical requirements of structures, systems and components.

Equipment Control Guideline (ECG) - These documents provide administrative controls and operability requirements for selected equipment that is not addressed by Technical Specifications (TS). ECGs are developed when controls are required by regulatory commitments or when plant management determines that it is prudent to control equipment to maximize its availability. TS that have been relocated to licensee-controlled documents are generally transferred to ECGs. Similar to TS, ECGs provide operability requirements, action statements, and surveillance requirements.

Field Change (FC) - The document used to request and approve minor changes to the design requirements of a Design Change Notice or Design Change Package that are within the original scope and intent of the design change document.

Jumper - A temporary modification typically referring to an electrical jumper, lifted electrical lead, mechanical bypass, or bypass of a safety function.

Licensing Basis, Current Licensing Basis (CLB) - The set of NRC requirements applicable to a specific plant and a licensee's written commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the regulations contained in 10 CFR parts 2, 19, 20, 21, 30, 40, 50, 51, 54, 55, 70, 72, 73, 100, and appendices thereto; orders; license conditions; exemptions; and Technical Specifications. It also includes the plant specific design basis information defined in 10 CFR 50.2 as documented in the most recent Final Safety Analysis Report as required by 10 CFR 50.71, and the licensee's commitments remaining in effect that were made in docketed licensing correspondence such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluation reports or licensee event reports. [from 10 CFR 54.3]

In its October 9, 1996, letter, the NRC stated, "*The licensing basis for a plant originally consists of that set of information upon which the Commission, in issuing an initial operating license, based its comprehensive determination that the design, construction, and proposed operation of the facility satisfied the Commission's requirements and provided reasonable assurance of adequate protection to public health and safety and common defense and security. The licensing basis evolves and is modified throughout a plant's licensing term as a result of the Commission's continuing regulatory activities, as well as the activities of the licensee*."

Licensing Basis Impact Evaluation (LBIE) - The review of the effects of a plant change (including but not limited to design changes), test, or experiment (CTE) on the licensing basis for DCPP, which documents (1) whether the CTE may proceed without prior NRC approval, and (2) the bases for reaching the above conclusion as required by regulations, the operating license and plant procedures. The LBIE process implements the requirements of 10 CFR 50.59, along with additional considerations in evaluating the significance of a CTE.

Maintenance Modification - A category of design change that is maintenance in nature (e.g., documentation, restorative, or operational maintenance).

Maintenance Modification Package (MMP) - A design change vehicle used for Maintenance Modifications that are recurring, affect the physical configuration of the

plant, and maintain a structure, system, or component. Once issued, MMPs are never closed and become design output documents.

Nonconformance Report (NCR) - A quality problem that constitutes a significant condition adverse to quality. To be classified as a nonconformance, a quality problem must satisfy one or more criteria explicitly defined in DCPP procedures, including, for instance, a substantial programmatic or implementation breakdown in the Quality Assurance Program; an issue identified at the request of plant management; etc.

Plant Information Management System (PIMS) - A computerized administrative system used by DCPP personnel to generate, track, and show status of resolution of plant-related activities, problems or actions, including design changes, action requests, maintenance, surveillance or other testing activities, training, dosimetry, plant component data, drawings, nonconformance reports, quality evaluations, commitments to the NRC, and other actions in plant operation.

Procedure Commitment Database (PCD)- The database subsystem used in the Plant Information Management System to track regulatory commitments that are implemented through DCPP procedures. A PCD commitment is a program commitment for which a step in a procedure or an entire procedure is necessary to ensure proper, consistent, and continual implementation.

Q-List - A controlled document that contains the listing and classification of DCPP structures, systems, and components according to design, quality, and code class requirements.

Quality Evaluation (QE) - A QE is a PIMS mechanism for processing a quality or balance-of-plant (BOP) problem. The QE mechanism contains provisions for documenting the problem, immediate corrective action, the cause of the problem, and corrective actions to prevent recurrence.

Replacement Part Evaluation (RPE) - An evaluation for determining the acceptability of a new or replacement part. This evaluation identifies critical characteristics necessary to ensure that the part supports the design basis functionality and any verification activities required to ensure that equivalent replacement parts meet those characteristics and are acceptable for use. RPEs may be part-specific, component-specific, or generic.

Supplier - Any individual or organization that furnishes items or services in compliance with a procurement document. The term supplier includes vendor, seller, contractor, subcontractor, fabricator, consultant, and subtier levels.

Temporary Modification - A modification to plant structures, systems, or components for a limited period of time after which the structure, system, or component is returned to its original configuration.

APPENDIX D - LIST OF ACRONYMS

Acronym	Terms
ACRS	Advisory Committee on Reactor Safeguards
ASLAB	Atomic Safety and Licensing Appeal Board
ASLB	Atomic Safety and Licensing Board
AE	Action Evaluation
ALARA	As Low As Reasonably Achievable
ANSI	American Nuclear Standards Institute
AR	Action Request
ASME	American Society of Mechanical Engineers
CDB	Component Database
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CMP	Configuration Management (Enhancement) Program
DART	Daily Action Request Review Team
DCE	Design Change Evaluation
DCM	Design Criteria Memorandum
DCN	Design Change Notice
DCP	Design Change Package
DCPIP	Design Change Process Initiative Project
DCPP	Diablo Canyon Power Plant
DBD	Design Basis Documentation
DLAP	Departmental Level Administrative Procedure
EAG	Engineering Assessment Group
EDSFI	Electrical Distribution System Functional Inspection
EIT	Event Investigation Team
EPRI	Electric Power Research Institute
ERT	Event Response Team

Appendix D - List of Acronyms

Acronym	Terms
ESAT	Engineering Self-Assessment Team
FC	Field Change
FSAR	Final Safety Analysis Report
IDAP	Interdepartmental Administrative Procedure
IDVP	Independent Design Verification Program
INPO	Institute of Nuclear Power Operations
IPRT	Integrated Problem Response Team
IRP	Internal Review Program
JUMA	Joint Utility Management Audit
LBIE	Licensing Basis Impact Evaluation
LER	Licensee Event Report
LTSP	Long Term Seismic Program
MMP	Maintenance Modification Package
MOV	Motor-Operated Valve
NCR	Nonconformance Report
NPG	Nuclear Power Generation
NQS	Nuclear Quality Services
NRC	Nuclear Regulatory Commission
NSOC	Nuclear Safety Oversight Committee
NSSS	Nuclear Steam Supply System
OTSC	On The Spot Change
PCD	Procedure Commitment Database
PD	Program Directive
PIMS	Plant Information Management System
POA	Prompt Operability Assessment
PRA	Probabilistic Risk Assessment
PSAR	Preliminary Safety Analysis Report

Appendix D - List of Acronyms

Acronym	Terms
PSRC	Plant Staff Review Committee
QA	Quality Assurance
QE	Quality Evaluation
RG	Regulatory Guide
RPE	Replacement Part Evaluation
SISIP	Seismically Induced System Interaction Program
SMR	Surveillance and Maintenance Requirements
SRO	Senior Reactor Operator
SSER	Supplemental Safety Evaluation Report
SSFAR	Safety System Functional Audit and Review
SSOMI	Safety System Outage Modification Inspection
STP	Surveillance Test Procedure
TRG	Technical Review Group
TS	Technical Specifications
TSOA	Technical Support Outage Assessment
USQ	Unreviewed Safety Question
WOG	Westinghouse Owners Group
WRJQAG	Western Region Joint Quality Assurance Group

APPENDIX E - INDEX

O

P

Q

R

S

T

V

W

December 23, 1997

PG&E Letter DCL-97-137

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

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Licensee Event Report 1-95-013-02
Component Cooling Water (CCW) System May Have Operated Outside of Its Design Basis Due to the Limited Capacity of the Auxiliary Saltwater System Combined With Increases in the Calculated Heat Load into the CCW System

Dear Commissioners and Staff:

Pursuant to 10 CFR 50.73(a)(2)(ii)(B), PG&E is submitting the enclosed revision to Licensee Event Report 1-95-013, which reported that the component cooling water system may have operated outside of its design basis. This revision provides information on the corrective actions to restore needed margin to the system.

This event did not adversely affect the health and safety of the public.

Sincerely,

Lawrence F. Womack

cc: Steven D. Bloom
Ellis W. Merschoff
Kenneth E. Perkins
David L. Proulx
Diablo Distribution
INPO

Enclosure
DPS/VAB/2246/N0001930

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Diablo Canyon Unit 1	0 5 0 0 0 2 7 5	1 OF 15

TITLE (4)

Component Cooling Water (CCW) System May Have Operated Outside of Its Design Basis Due to the Limited Capacity of the Auxiliary Saltwater System Combined With Increases in the Calculated Heat Load into the CCW System

EVENT DATE (5)				LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MON	DAY	YR	YR	SEQUENTIAL NUMBER	REVISION NUMBER	MON	DAY	YR	FACILITY NAME	DOCKET NUMBER
10	10	95	95	- 0 1 3 -	0 2	12	23	97	Diablo Canyon Unit 2	0 5 0 0 0 3 2 3

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11)		
1	X	10 CFR	50.73(a)(2)(ii)(B)
POWER LEVEL (10)		OTHER	
1 0 0			(SPECIFY IN ABSTRACT BELOW AND IN TEXT, NRC FORM 366A)

LICENSEE CONTACT FOR THIS LER (12)

	TELEPHONE NUMBER	
	AREA CODE	
Vickie A. Backman - Senior Regulatory Services Engineer	805	545-4289

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NRPDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NRPDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MON	DAY	YR
[ ] YES (If yes, complete EXPECTED SUBMISSION DATE)	[X] NO				

ABSTRACT (16)

On October 10, 1995, at 1700 PDT, with Unit 1 defueled and Unit 2 in Mode 1 (Power Operation) at 100 percent power, a review of performance test results determined that residual heat removal heat exchanger thermal performance was more efficient (non-conservative) than had been assumed in the component cooling water (CCW) system analysis. On October 10, 1995, at 1715 PDT, this condition was reported to the NRC for Unit 1 as a 4-hour, non-emergency report in accordance with 10 CFR 50.72(b)(2)(i), and for Unit 2 as a 1-hour, non-emergency report in accordance with 10 CFR 50.72(b)(1)(ii)(B).

This event was caused by the limited capacity of the auxiliary salt water (ASW) system. Increases in the calculated heat load into the CCW over the past 20 years resulted in a decrease in the design margin in the CCW system to a minimum.

A design change and TS bases change have been completed revising peak allowable CCW system temperature to 140 degrees Fahrenheit for up to 6 hours. Related design basis documents are being revised to support the design change.

TEXT

I. Plant Conditions

Unit 1 was defueled and Unit 2 was in Mode 1 (Power Operation) at 100 percent power. Both Units 1 and 2 have operated in various modes with the potential for the condition described in this LER.

II. Description of Problem

A. Summary

On October 10, 1995, at 1700 PDT, with Unit 1 defueled and Unit 2 in Mode 1 at 100 percent power, a review of thermal performance testing results determined that Residual Heat Removal (RHR) Heat Exchanger (BP)(HX) 1-1 was more efficient than had been assumed in the design basis analysis. For component cooling water (CCW) system (BI) overheating analysis, this is non-conservative.

On October 10, 1995, at 1715 PDT, this condition was conservatively reported to the NRC for Unit 1 as a 4-hour, non-emergency report in accordance with 10 CFR 50.72(b)(2)(i), and for Unit 2 as a 1-hour, non-emergency report in accordance with 10 CFR 50.72(b)(1)(ii)(B).

B. Background

The CCW system is designed to provide normal plant operational and post-accident cooling to the containment fan cooler units (CFCUs) (BK)(CLR), RHR HXs, skid coolers (SJ)(CLR) for the centrifugal charging pumps (CCPs) (SJ)(P), safety injection (SI) pumps (BQ)(P), CCW pumps(BI)(P), RHR pumps (BP)(P), and post-accident sampling system coolers (IP)(CLR). Additionally, the CCW system removes heat from nonvital components via the system's nonvital C Header. The waste heat from the vital and nonvital components is rejected to the ultimate heat sink via the auxiliary saltwater (ASW) system (KE). Under accident conditions, the cooling water flow to the nonvital loads is automatically isolated by closure of flow control valve FCV-355. The Final Safety Analysis Report (FSAR) Update and Supplemental Safety Evaluation Report (SSER) Number 16 contain a 132 degrees Fahrenheit (F) upper limit, remaining above 120 degrees F for no more than 20 minutes, to assure availability of vital equipment.

The CCW system temperature is a function of several factors, including the heat loads on the system, the number of CCW HXs in service, the number of ASW pumps in service, as well as the temperature of the ultimate heat sink. Following a design basis large break loss of coolant accident (LOCA)

TEXT

or main steam line break (MSLB), large amounts of energy are released into containment. This significantly increases the heat load placed on the CCW system by the CFCUs. The heat load on the system is further increased when the RHR HXs are placed in operation to cool the water collected in the containment sump.

PG&E letters dated March 18, April 4, and May 18, 1983, provided the results of a reanalysis of the heat removal capability of the CCW system, assuming the worst design basis heat load resulting from a LOCA and the most limiting single active failure. The NRC's review of the reanalysis is documented in SSER 16. Subsequent to that analysis, several conditions, such as those documented in PG&E letters DCL 88-215, dated September 13, 1988, and DCL 92-148, dated June 29, 1992, have reduced the reported margin in the 1983 analysis of the CCW system. Each of these conditions were due to changes in assumptions made in the 1983 analysis. Actions taken following these submittals include performance of a new Westinghouse mass and energy release model for post-LOCA containment analysis, a review of the CCW overheating analysis, and revisions to emergency operating procedures.

In 1995, a new CCW overheating analysis was performed by Westinghouse using the new LOCA mass and energy release model to demonstrate that a single ASW pump and a single CCW HX provide sufficient cooling to maintain the CCW temperature within its design basis limits assuming the most limiting accidents. This analysis is conservative since, as stated in the FSAR Update, a second CCW HX is credited to be placed in service within 20 minutes. The analysis assumed that the ASW pump flow rate satisfied the requirements of Surveillance Test Procedure (STP) M-26, "ASW System Flow Monitoring," and design CFCU and RHR HX fouling factors of 0.0005 and 0.0008, respectively. The Westinghouse analysis identified three accident scenarios which resulted in the limiting CCW temperature transients. These were:

1. An MSLB with an assumed failure of the secondary side isolation which results in high CCW temperatures in the short term. Following the isolation of the faulted steam generator, containment and the CCW system cool rapidly.

2. A LOCA with a failure of an ASW pump which results in the worst case CCW temperature transient during the injection phase.

TEXT

3. A LOCA with a failure of Solid State Protection System (SSPS) Train A which results in the worst case CCW temperature transient in the recirculation phase of an accident.

The analysis performed for the LOCA with an SSPS Train A failure, concluded that the CCW temperature would remain below 132 degrees F but would exceed 120 degrees F for greater than 20 minutes (26.1 minutes), assuming no operator action to align a second CCW HX.

Technical Specification (TS) 3.5.5, "Emergency Core Cooling Systems - Refueling Water Storage Tank," specifies the operability of the refueling water storage tank (RWST) to ensure an adequate supply of borated water is available to cool and depressurize the containment in the event of a design basis event.

TS 3/4.6.2.3, "Containment Systems - Containment Cooling System," specifies the operability of the CFCUs to ensure that adequate containment heat removal capacity is available when operated in conjunction with the containment spray systems during post-LOCA conditions.

TS 3/4.7.3.1, "Plant Systems - Vital Component Cooling Water System," specifies the operability of the vital CCW system to ensure that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions.

TS 3/4.7.12, "Plant Systems - Ultimate Heat Sink," specifies the operability of the ultimate heat sink to ensure the CCW temperature remains equal to or less than 132 degrees F during any condition assumed in the safety analysis. One CCW HX is required to be in service when the ocean temperature is 64 degrees F or less. Two CCW HXs are required in service when the ocean temperature is greater than 64 degrees F. If the reactor coolant system temperature is less than 350 degrees F, one CCW HX in service is adequate even if the ocean temperature is greater than 64 degrees F.

STP M-26 verifies that the ASW flow through the CCW HXs is sufficient to meet design basis requirements of the ASW and CCW systems.

Operating Procedure (OP) F-2.III, “Component Cooling Water System Shutdown and Cleaning,” ensures that during CCW HX maintenance, either the opposite unit’s standby ASW pump through the unit crosstie valve, the second ASW pump, or the second CCW HX can be returned to service within 20 minutes by manual operator action. An alternate maintenance

TEXT

compensatory action is the performance of Plant Engineering Procedure (PEP) M-229, "Evaluation to Allow Taking Credit for a Single Train ASW for a Specific Duration of Time for Maintenance/Operations Evolutions," to ensure CCW system capability.

STP R-20, “Boric Acid Inventory,” provides for the measurement of the RWST water volume, boron concentration, and temperature to meet TS 3.5.5 and design requirements.

C. Event Description

Generic Letter 89-13 allows exemption of closed cooling water systems with good chemistry controls from performance testing. The CCW system is a closed cooling system which has historically maintained good chemistry control with the use of chromate as both a corrosion inhibitor and an effective biocide. The chromates were changed in 1991 to a more environmentally acceptable molybdate-based inhibitor. Since this change, a concern was raised that microbe growth may have degraded heat transfer capabilities.

PG&E conducted a number of tests and inspections to better understand the microfouling and its effect on heat transfer capability. A thermal performance test was conducted on RHR HX 1-1 during the cooldown phase at the start of the Unit 1 seventh refueling outage (1R7). The test results indicated that the HX was capable of transferring more heat to the CCW system than assumed in safety analysis calculations because of a lower than expected fouling factor.

The HXs are sized to ensure that fouling does not degrade the HX performance to below design specifications. LOCA analyses assume that heat transfer capability is reduced due to fouling. The assumed design fouling factor is 0.0008 hr-ft^2-ºF/Btu (0.0005 hr-ft^2-ºF/Btu on the shell side plus 0.0003 hr-ft^2-ºF/Btu on the tube side). This assumption is conservative with respect to containment analysis, but is non-conservative in the CCW system overheating analysis. Based on an analysis of the 1R7 test results, it was judged that the use of a fouling factor as low as 0.0001 hr-ft^2-ºF/Btu was appropriate.

Because of similar water chemistry conditions, it is conservatively assumed that the same condition exists for the other RHR HX and for the CFCUs, so that they also reject heat to CCW at a higher rate than assumed in the analysis. The CFCU design fouling factor is 0.0005 hr-ft^2-ºF/Btu. At the same time, the fouling factor for the CCW HX is conservatively assumed to

be at its design value of 0.001. Finally, because the same water chemistry control program is in effect for both units, this concern was conservatively assumed to exist on Unit 2.

These lower fouling factors were used to assess the heat input to the CCW system from the RHR HXs and the CFCUs. The FSAR Update and SSER 16 contained a 132 degrees F upper limit, remaining above 120 degrees F for no more than 20 minutes to assure availability of vital equipment. An analysis using a new Westinghouse containment mass and energy release methodology showed that the FSAR Update and SSER CCW temperature limits could have been exceeded during the LOCA recirculation phase if only one CCW HX was in operation (during CCW HX maintenance). PG&E has judged that the CCW system would also have exceeded the temperature limits stated in the FSAR Update and SSER 16 if the old containment mass and energy release methodology had been used.

On October 10, 1995, at 1715 PDT, this condition was conservatively reported to the NRC as a 4-hour, non-emergency report in accordance with 10 CFR 50.72(b)(2)(i) for Unit 1, and as a 1-hour, non-emergency report in accordance with 10 CFR 50.72(b)(1)(ii)(B) for Unit 2. A preliminary operability evaluation (OE) was issued with applicable compensatory measures.

On November 17, 1995, a formal OE was approved and compensatory measures were established to ensure that the CCW temperature profile remains within its design limits until corrective actions can be completed to provide additional CCW system design margin.

PG&E letter DCL 95-265, dated December 11, 1995, submitted the new Westinghouse containment analysis using the new mass and energy release methodology to the NRC and committed to perform 10 CFR 50.59 evaluations to include the new Westinghouse containment analysis in the Units 1 and 2 design basis. PG&E letter DCL 95-265, also committed that a 10 CFR 50.59 evaluation would be performed to reflect the new design basis in the next scheduled revision of the FSAR Update. The 10 CFR 50.59 evaluations were approved and became the design basis of record on January 17, 1996. The FSAR Update was issued on November 25, 1996, via PG&E Letter DCL 96-225.

On April 25, 1997, a design change was issued changing the CCW system temperature from a peak of 132 degrees F for no longer than 30 minutes and 120 degrees F thereafter, to a peak of 140 degrees F for no longer than 6 hours and 120 degrees F afterwards.

TEXT

D. Inoperable Structures, Components, or Systems that Contributed to the Event

None.

E. Dates and Approximate Times for Major Occurrences

1. October 10, 1995, at 1700 PDT: Event date/discovery date - Evaluation of HX test results determine RHR HX heat transfer coefficient is non-conservative.

2. October 10, 1995, at 1715 PDT: Condition was reported to the NRC as a 4-hour, non-emergency report in accordance with 10 CFR 50.72 (b)(2)(i) for Unit 1, and a 1-hour, non-emergency report in accordance with 10 CFR 50.72 (b)(1)(ii)(B) for Unit 2.

F. Other Systems or Secondary Functions Affected

None.

G. Method of Discovery

After changing the inhibitors used to maintain chemistry control of the closed loop CCW system, PG&E observed microfouling. A thermal performance test of RHR HX 1-1 initiated to evaluate the effect of microfouling identified that the heat transfer capability of the RHR HX was non-conservative relative to that used in the CCW overheating analysis.

H. Operator Actions

None.

I. Safety System Responses

None.

TEXT

III. Cause of the Problem

A. Immediate Cause

The heat transfer coefficient for the RHR HXs and CFCUs is greater than the heat transfer coefficient used in the CCW system analysis. Actual fouling was significantly less than the fouling factor used in the design basis analysis. This was non-conservative for evaluating the maximum CCW temperature profile conditions.

B. Root Cause

This event was caused by the limited capacity of the ASW system. Increases in the calculated heat load into the CCW system since 1983 have reduced the design margin in the system to a minimum.

IV. Analysis of the Event

Evaluation of the following conditions have been performed as discussed below:

- New containment analysis (without compensatory measures)
- New containment analysis (with compensatory measures)
- Old containment analysis (without compensatory measures)
- Evaluation of lower fouling factors on other heat loads

A. New Containment Analysis (without compensatory measures):

The assumed reduction in the fouling of the CFCUs and RHR HXs to 0.0001 results in an increase in the heat transferred into the CCW system. This results in higher post-accident CCW system temperatures. To assist in evaluating the impact of the reduced fouling factors on the CCW temperature transient, Westinghouse determined the CCW temperature profile which results from various postulated scenarios. This work was performed using the new Westinghouse mass and energy release methodology. An RWST temperature of 90 degrees F was assumed for all cases. A PG&E calculation demonstrates that the water in the RWST has never exceeded this temperature. Each of the limiting scenarios is discussed below.

1. Effect of Reduced Fouling on CCW Temperatures Following an MSLB:

The analysis of the impact of the lower fouling factor on the results of the MSLB analysis indicated that the CCW temperature reaches a

peak of 132.09 degrees F before dropping rapidly. At the time, this was essentially equal to the design basis CCW temperature limit of 132 degrees F. The analysis was performed by conservatively estimating the CFCU heat input increases by 20 percent as a result of the decreased fouling. Westinghouse CFCU analysis later demonstrated that the actual increase in heat transfer would be less, and therefore it was judged that the peak CCW temperature would have been less than 132 degrees F.

In Revision 1 of this LER, PG&E noted, in error, that Westinghouse had performed the MSLB analysis assuming only one ASW pump was in service. Since the MSLB analysis already assumes a single active failure on the secondary side, the second ASW pump would be in operation. In the process of revising the CCW overheating analysis, PG&E realized that Westinghouse did assume two ASW pumps were in operation. Therefore, there was not as much margin to the old 132 degrees F limit as previously thought. The revised CCW analysis, currently being finalized, will document that the CCW temperatures are well within the current design temperature limits.

2. Effect of Reduced Fouling on CCW Temperatures During LOCA Injection Phase:

   Westinghouse analysis, using the new mass and energy release methodology, determined that the limiting LOCA injection phase accident resulted in peak CCW temperatures that were lower than the MSLB case. It is judged that the MSLB would remain the bounding short term temperature transient even with the new lower fouling factors. Because Westinghouse has demonstrated that the CCW design basis temperature limits were not exceeded by the MSLB, it can be concluded that the LOCA injection phase transient is acceptable as well.

3. Effect of Reduced Fouling on CCW Temperatures During LOCA Recirculation Phase:

   The impact of the lower CFCU and RHR HX fouling on the LOCA recirculation phase accident with an assumed failure of SSPS Train A was evaluated. The alignment of the second CCW HX at the start of recirculation keeps the CCW temperature profile within its design basis limits. Although not credited, operator alignment of the second ASW pump would have further reduced the peak CCW temperature transient. Therefore, the decreased fouling does not result in

exceeding the old CCW design basis temperature limit for this limiting scenario.

4. Effect of Maintenance of the CCW HX on CCW Analysis:

In addition to the cases discussed above, the maintenance of a CCW HX within the 72 hour TS allowed outage time action statement with no additional single active failures was evaluated.

Existing CCW HX clearance practices resulted in having only a single ASW pump providing flow to a single CCW HX when the other HX is in maintenance. Existing recirculation phase analyses assumed that a second CCW HX would be aligned within 20 minutes. Depending on the actual maintenance under way, it may not have been possible to align the second HX in 20 minutes.

To analyze the condition that existed before compensatory measures were implemented, Westinghouse performed an analysis assuming only one ASW pump and one CCW HX were available. A reduced RHR HX fouling factor and a 20 percent increase in CFCU heat load were conservatively assumed as an estimate of the impact of reduced fouling. Although no single active failure needs to be postulated, the analysis also assumed that an SSPS train failure had occurred. This analysis predicted a peak CCW temperature less than 132 degrees F, but the temperature remains above 120 degrees F for approximately 139 minutes. This exceeded the old design basis limit of 20 minutes. Note that this analysis was performed using the new containment mass and energy release methodology. It is judged, that had the above case been run without the additional single active failure of the SSPS train, the CCW system would still have exceeded 120 degrees F for more than 20 minutes. It is also judged that CCW temperature would still have exceeded the design basis temperature limits using the old containment mass and energy release methodology. Therefore, Unit 1 and/or Unit 2 may have operated in a condition outside the design basis of the plant.

Acceptability of this past condition is demonstrated by the following evaluation of equipment. A review of the RHR, SI, and CCW pumps performed by Westinghouse in 1994, indicated that these pumps would be qualified for operation at, or above, 120 degrees F for as much as six hours. The Westinghouse qualification of the CCPs for the higher CCW temperature was based on a minimum flow to the skid coolers. Skid flow measurements indicated that the actual flow to the coolers

TEXT

may have been less than that used to qualify the CCPs. PG&E has demonstrated, that the impact of the reduced flow rates would have been small, and therefore the CCPs would have been capable of performing their design basis function. The CCW pumps were reviewed by Sulzer-Bingham, the pump manufacturer, and they indicated that the pumps can operate with elevated cooling water temperatures as high as 140 degrees F for up to 24 hours. Based on the vendor input, and supported by PG&E's analysis, it was judged that operation above the existing temperature limit of 120 degrees F for a period of 139 minutes would not have prevented the CCW system from performing its design basis function in the event of a design basis accident while performing maintenance activities on the CCW HX.

It should be noted that the CCW temperature profile for the CCW HX cleaning scenario, without compensatory measures evaluated above, was provided by Westinghouse for information only. A similar evaluation was performed using the same assumptions except that an RWST temperature of 80 degrees F was used. This evaluation was checked and the results were provided in the same reference. A comparison of the checked and unchecked cases shows a consistency of the results relative to the design inputs. This provides confidence that the unchecked cases may be used as the basis for the engineering judgments made above.

Since this evaluation was performed, PG&E has completed a design change to increase the design basis temperature limit of the CCW system to 140 degrees F for 6 hours and 120 degrees F, thereafter.

B. New Containment Analysis (with compensatory measures):

As discussed previously in this LER, compensatory measures have been taken to prevent the CCW system from exceeding its design basis temperature limits during periods when a CCW HX is in maintenance. This includes a revision to STP R-20 to assure that the RWST temperature does not exceed 80 degrees F. In addition, the procedure for clearing a CCW HX has been revised to assure that adequate ASW flow will be available to prevent CCW overheating. This is accomplished by either assuring that a second ASW pump can be aligned within 20 minutes or by verifying that the ASW flow from one pump is high enough to prevent the CCW system from exceeding its design basis temperature limits. Although the design basis temperature limits have now been increased, these compensatory measures will remain in effect until the CCW overheating analysis is revised.

TEXT

Several analyses were performed assuming a fouling factor of 0.0001 hr-ft^2-ºF/Btu for both the RHR HX and the CFCUs and a reduction in RWST temperature to 80 degrees F as discussed below. These analyses conservatively assumed an SSPS train failure had also occurred.

One analysis was run assuming a second ASW pump is available before the start of the recirculation phase. This case met the old design basis requirements; staying over 120 degrees F for only 7 minutes.

Other analyses were performed to determine how much ASW flow is required for a given ASW temperature assuming only one ASW pump is running. These analyses produced a table of required ASW flow as related to temperature for one ASW pump and one CCW HX operation. These required flows are higher than those verified by the ASW STP M-26. This table was incorporated into PEP M-229. An evaluation can be performed using PEP M-229 along with flows measured by the ASW STP and other factors to allow a CCW HX to be taken out-of-service.

Current compensatory measures assure that either the evaluation discussed above is performed or measures are taken to ensure that a second ASW pump (crosstied from the other unit) can be aligned before the start of recirculation.

TEXT

C. Old Containment Analysis (without compensatory measures):

Although the new mass and energy release analysis methodology did not become part of the Diablo Canyon Power Plant design basis until January 17, 1996, the old Westinghouse mass and energy release methodology was not used in evaluating this event. The new analysis is considered more accurate and realistic than the old analysis. As discussed above, the new analysis demonstrates that the CCW system would have performed its design basis function following a design basis accident even before compensatory measures were in place. Thus, the old analysis methodology is not needed to evaluate past operability and the health and safety of the public were not affected by this event.

D. Evaluation of Lower Fouling Factors on Other Heat Loads:

The heat input to the CCW system following a LOCA or MSLB comes primarily from the RHR HXs and the CFCUs. The impact of lower fouling factors on these components has already been analyzed. The balance of the vital component heat loads are small by comparison, and therefore the impact of lower fouling on these components would not significantly alter the CCW temperature profile.

CCW has a nonvital C Header which provides cooling to nonvital components. In the event of a large break LOCA or MSLB, a signal is generated to isolate the C Header. Accordingly, the potentially lower fouling of the C Header components would only impact the CCW temperature transient if the C Header fails to automatically isolate, and then only until the beginning of the recirculation phase when the C Header is manually isolated. An evaluation of the failure of C Header to isolate during a large break LOCA injection phase was conducted and it was judged that there is enough margin to accommodate lower fouling without exceeding the CCW temperature limits. Further, the limiting MSLB includes a failure of the secondary side isolation. Accordingly, the additional failure of the C Header to isolate does not need to be postulated.

The scenarios evaluated for this event bound all operating evolutions the plant has experienced. Though for some scenarios, the design temperature would be exceeded, all equipment would have fulfilled its design functions. Thus, the health and safety of the public were not affected by this event.

TEXT

V. Corrective Actions

A. Immediate Corrective Actions

The following compensatory measures were initiated as part of OE 95-11. The OE will remain in place until the revised CCW overheating analysis is completed.

1. Initially, the second CCW HX was aligned and left in operation. Subsequent analysis, however, determined that placing one CFCU in manual would achieve a similar result with less potential adverse effects. Therefore, one CCW HX was placed in operation and one of the five CFCUs was administratively removed from service (cleared) to the shift supervisor. This action is no longer required due to the new containment analysis 10 CFR 50.59 evaluation approved on January 17, 1996.

2. OP F-2.III has been revised to ensure the capability for return-to-service of either the opposite unit's standby ASW pump through the unit crosstie valve, the second ASW pump, or the second CCW HX within 20 minutes. Alternately, an engineering evaluation for ASW single train capability per PEP M-229 is performed for the maintenance activity.

3. STP R-20 has been revised to assure that the RWST water temperature is not more than 80 degrees F.

B. Corrective Actions to Prevent Recurrence

1. A design change and TS bases change have been issued to change the peak CCW system temperature to 140 degrees F for up to 6 hours and 120 degrees F, thereafter.

2. The CCW system overheating analysis in WCAP-14282 is being revised to demonstrate that the system will remain within the new design basis temperature limits without the compensatory measures in place.

3. OE 95-11 will be closed after WCAP-14282 Revision 1 is reviewed and accepted by PG&E.

TEXT

VI. Additional Information

A. Failed Components

None.

B. Previous LERs on Similar Problems

LER 1-91-018-01, submitted on June 29, 1992, reported that the heat load on the CCW system during the cold leg recirculation phase following a LOCA could potentially exceed the heat load during the injection phase. Because the injection phase had previously been considered to be the limiting case for CCW temperature, this condition was considered to be outside the design basis of the CCW system. The root cause was attributed to personnel error. The corrective actions to prevent recurrence included additional training for design engineers to emphasize that data known to be conservative for one application, may be non-conservative for another application. These corrective actions could not have prevented the condition reported in this LER since these conditions existed before the corrective actions were effective.

LER 1-93-001, submitted on February 12, 1993, reported that under a combination of worst-case conditions and parameters, the CCW system water temperature design basis temperature limits may be exceeded. The root cause of this event was non-conservatism in the design basis analysis for the CCW system. Corrective actions were procedural revisions to improve flow balancing. These corrective actions could not have prevented the condition reported in this LER since these conditions existed before the corrective actions were effective.

January 12, 1998

PG&E Letter DCL-98-007

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

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Reply to NRC Inspection Report Nos. 50-275/97-202 and 50-323/97-202

Dear Commissioners and Staff:

NRC Inspection Report (IR) Nos. 50-275/97-202 and 50-323/97-202, dated November 13, 1997, documented the results of the Design Inspection performed by the NRC from August 4 to September 11, 1997. Appendix A to the IR identified ten open items, five unresolved items (URIs) and five inspection follow-up items (IFIs) as listed in Enclosure 1. In the NRC's IR cover letter, the NRC requested that PG&E provide a schedule within 60 days detailing its plans to complete the corrective actions for each of the open items listed in Appendix A to the report. Actions taken and/or planned to address each of these items and the status/schedule for their completion are provided in Enclosure 2.

Two of the URIs identified in the IR involve issues that the inspection team identified as potential unreviewed safety questions (USQs). One issue involves the capability of the component cooling water and auxiliary saltwater systems to withstand a single passive failure when the trains are crosstied or a single active failure when the trains are split. The second issue involves the availability of the containment spray function during the recirculation mode of operation after an accident. PG&E considers that the actions taken under the 10 CFR 50.59 process to address these issues were correct, and that these issues do not involve USQs. Nonetheless, there were errors associated with the resolution of the spray during recirculation issue in 1991 and 1992, and we have/are continuing to take corrective actions relative to those administrative problems.

The IR also notes the expectation that PG&E will evaluate the applicability of the results and specific findings of the NRC design inspection to other systems and components throughout the plant. The issues identified by the inspection team, including the open items for which a response was requested, were entered into the PG&E problem reporting system. This system, governed by Program Directive OM7, “Problem Resolution,” ensures that generic issues are addressed as appropriate and corrective actions are taken as necessary to preclude recurrence. Enclosure 2 identifies specific actions taken where appropriate to address potential generic implications of the specific issues identified in Appendix A of the IR. The overall number of issues identified by this extensive examination, and by PG&E’s own programs, is relatively small and does not involve loss of safety-related functionality. PG&E believes that, individually or collectively, the issues do not indicate any programmatic failures that would not be corrected by our normal processes. However, the generic implications of the aggregated errors in the Final Safety Analysis Report Update (UFSAR), Design Criteria Memoranda (DCMs), and other design basis related documents will continue to be examined during the completion of PG&E’s response to the NRC’s 10 CFR 50.54(f) letter regarding adequacy and availability of design bases information. The Licensing and Design Basis Alignment Program will assure that no further actions beyond the normal problem resolution program are required.

In addition, the IR requests PG&E to evaluate the inspection findings, both specific and programmatic, against PG&E’s response to the NRC's request for information pursuant to 10 CFR 50.54(f) regarding adequacy and availability of design bases information. Although the inspection team identified inconsistencies between various design basis documents, PG&E remains confident that, as implemented, the design and configuration control processes at Diablo Canyon Power Plant (DCPP) provide reasonable assurance that the plant is being maintained and operated in accordance with its design bases as defined in 10 CFR 50.2. Nonetheless, consistent with commitments made in conjunction with PG&E’s 10 CFR 50.54(f) response, PG&E will continue to pursue the actions to maintain and enhance the integrity of the DCPP design and licensing bases as delineated in PG&E letter DCL-97-018, Request for Information Pursuant to 10 CFR 50.54(f) Regarding Adequacy and Availability of Design Basis Information dated February 6, 1997, including the performance of additional licensing documentation review (UFSAR) and further training in the areas of configuration management, UFSAR, and 10 CFR 50.59 evaluations. These actions also include further reviews of procedures against the DCMs and continuing focused Quality Assurance audits to assess PG&E’s performance in ensuring conformance with the DCPP design bases.

Sincerely,

Lawrence F. Womack

cc: Steven D. Bloom
Ellis W. Merschoff
Kenneth E. Perkins
David L. Proulx
Diablo Distribution
INPO

Enclosures

SCK/2237

NRC Inspection Report (IR) Nos. 50-275/97-202 and 50-323/97-202
Inspection Open Items

Open Item	Type	Subject
50-275/97-202-01	IFI	Review of UHS Calculation for Maximum UHS Temperature at Which the Plant Can be Operated Without Exceeding ASW System Design Limits (Section E1.2.1.2.c)
50-275/97-202-02	IFI	Review of Revision to WCAP-14282 and Incorporation of Revised WCAP-14282 Into Design Bases Documentation (Section E1.2.1.2.c.2)
50-275/97-202-03	URI	Determine if Long-Term Post-LOCA Operation of ASW System With Both Trains Tied Together Represents a USQ (Section E1.2.1.2.d)
50-275/97-202-04	IFI	ASME Section XI Testing of ASW Pumps (Section E1.2.1.2.f)
50-275/97-202-05	URI	Discrepancy in Design Documentation (Sections E1.2.1.2.g, E1.2.3.2.e, E1.3.3.2.a, E1.3.3.2.d)
50-275/97-202-06	URI	Availability of an Alternate Flowpath for the ASW System Section (Section E1.2.1.2.h)
50-275/97-202-07	URI	EDG Transient Analysis Computer Simulation Study (Section E1.2.2.2.a)
50-275/97-202-08	IFI	Control of Calculations (Section E1.2.2.2.c, E1.2.2.2.i)
50-275/97-202-09	IFI	Review of Battery Charger Settings (Section E1.2.2.2.d)
50-275/97-202-10	URI	Potential USQ and TS Adherence Associated With Containment Spray During Containment Recirculation (Section E1.3.1.2.b & c)

IFI = Inspection Follow-up Item
URI = Unresolved Item

REPLY TO INSPECTION REPORT
NOS. 50-275/97-202 AND 50-323/97-202

On November 13, 1997, as part of NRC Inspection Report (IR) Nos. 50-275/97-202 and 50-323/97-202, the NRC opened five unresolved items (URIs) and five inspection follow-up items (IFIs). The IR requested that PG&E provide a schedule within 60 days detailing its plans to complete the corrective actions for the open items listed in Appendix A to the report. The required actions and associated schedules are documented below. For each open item, the description of the issue as stated in the IR is provided.

1. ***IFI 50-275/97-202-01:*** *Review of UHS Calculation for Maximum UHS Temperature at Which the Plant can be Operated Without Exceeding ASW System Design Limits (Section E1.2.1.2.c)*

   Item Description *- ASW system temperature is controlled by TS 3/4.7.12 which requires that the second CCW heat exchanger be placed in operation when the ocean temperature exceeds 64°F. Flow requirements are verified through regular surveillance testing (see section E1.2.1.f). Because of the effects of "EL Nino" on ocean temperature, the team questioned the licensee as to maximum ocean temperature limits that would continue to allow safe operation. DCPP could not identify the maximum ocean temperature at which the plant could be operated with both CCW heat exchangers in operation to maintain CCW and ASW systems within their existing design limits. At the time of exit, DCPP was preparing a calculation to determine the maximum UHS temperature at which the plant could be operated, and this has been left as a follow-up item.*

   Response - Three calculations have been performed to determine the maximum ultimate heat sink (UHS) temperature at which Diablo Canyon Power Plant (DCPP) can be operated. Each calculation evaluates a specific range of operating configurations. Taken together, these calculations establish the limit of operation with elevated UHS temperatures.

   - The first calculation, M-1027, assesses the limits on operation in Modes 1 through 3. This calculation concludes that operation of DCPP with two component cooling water (CCW) heat exchangers in service and with UHS temperatures as high as 75°F is acceptable.
   - The second calculation was performed to address a special case not included in Calculation M-1027, operation following a loss-of-coolant accident (LOCA) with two auxiliary saltwater (ASW) pumps and two CCW heat exchangers in service. This calculation is addressed as Case 9 of WCAP-14282, Revision 1, which was issued to update the CCW heatup analysis to address various technical issues identified since its initial issue. Calculation M-1027 determined that operation of DCPP in this configuration is acceptable with an UHS temperature as high as 80°F.

- The third calculation, M-1020, determines the maximum UHS temperature for which a single CCW heat exchanger may support Mode 4 (Hot Shutdown) operation. The DCPP Technical Specifications (TS) require that if a second CCW heat exchanger cannot be placed into service within 8 hours when the UHS exceeds 64°F, then the plant must go to Mode 4. Calculation M-1020 determined that adequate heat removal capability was available with UHS temperatures as high as 70°F.

All three calculations referenced above, including WCAP-14282, Revision 1, have been completed and issued. Based on these three calculations, an UHS upper temperature limit has been established as 70°F. This limit will be incorporated into the design basis by Design Change Package (DCP) M-49386. DCP M-49386 will be implemented by June 1, 1998. Information regarding the maximum UHS temperature will be added to the Improved Technical Specifications (ITS) as part of the response to a request for additional information associated with Section 3.7 of the ITS. This request is expected to be received in approximately May 1998, with the information submitted approximately 30 days following the receipt of the request.

This limit was not part of plant analysis or procedure in the past based on knowledge of system performance and recognition that historical ocean temperatures essentially precluded it from being a limiting factor. While that was still believed to be true, the questions associated with the inspection and the El Nino phenomenon led to formalization of this limit, thus confirming past judgment.

Because of the system specific nature of this issue, lack of similar issues, and the confirmation of past judgment, no further generic considerations are warranted.

2. ***IFI 50-275/97-202-02:*** *Review of Revision to WCAP-14282 and incorporation of revised WCAP-14282 into design bases documentation (Section E1.2.1.2.c.2)*

   Item Description *- At the time of the inspection, WCAP-14282 was in revision to finalize the preliminary analysis done in PGE-96-503 and to also capture the history and the effect of the CCW system changes on all interfacing systems. Issue of the revised WCAP-14282 will also supersede/revise a number of calculations and design documentation including DCMs and the UFSAR. The changes necessary to incorporate revised WCAP-14282 into design bases documentation is being tracked by DCPP under AR A0439116.*

   Response - WCAP-14282, Revision 1, was issued on December 12, 1997. WCAP-14282, Revision 1, will be incorporated into the DCPP design basis by DCP M-49386 which is currently in preparation. In conjunction with incorporating the results of WCAP-14282 into the design basis, DCP M-49386 will implement changes to the Final Safety Analysis Report Update (UFSAR), as well as various design criteria memoranda (DCMs), procedures

and calculations relating to CCW/ASW system operation. As discussed above, DCP M-49386 will be implemented by June 1, 1998.

The unique nature of the cooling systems and their limitations, and the need to update these analyses and associated documentation were recognized before the inspection, and have been addressed. No further generic considerations are required.

3. ***URI 50-275/97-202-03:*** *Determine if Long-term post-LOCA Operation of ASW System With Both Trains Tied Together Represents a USQ (Section E1.2.1.2.d)*

   Item Description *- The team reviewed the ability of the ASW system to be separated into two redundant trains for long term post-LOCA cooling as described in UFSAR section 9.2.7.2, and as was the intent of the original design. The team determined that the ASW system, in combination with CCW system, could withstand a single active failure during all phases of accident mitigation as long as the trains remained mechanically cross-tied. The ASW system is currently configured to operate with both trains tied together. DCPP EOP E-1.4, "Transfer to Hot Leg Recirculation," originally required separation of the ASW and the CCW systems into isolated trains approximately 10 1/2 hours after the LOCA. The EOP was revised as part of LER 97-001-00 corrective action and the trains are now separated during long term cooling based on a decision to be made by the TSC to separate the trains to be able to withstand a single passive failure in the fluid system. The team determined that this ASW system operation did not form the original bases for the ASW system design or licensing, and was a potential unreviewed safety question (USQ) that needed to be further evaluated by the NRC.*

   Response - In early 1997, prior to the NRC Design Inspection, PG&E identified that realigning the ASW/CCW system into two separate trains created a vulnerability to a single active failure of an electrical power supply. This concern was addressed in Nonconformance Report (NCR) N0002010 and reported to the NRC in License Event Report (LER) 1-97-001-00. The corrective actions to address this condition have been completed. They included:

   - The UFSAR was revised to have the Technical Support Center (TSC) direct the separation of the ASW/CCW trains.
   - Emergency Operating Procedure (EOP) E-1.4, “Transfer to Hot Leg Recirculation,” was revised to have the operators consult the TSC on the separation of the ASW/CCW trains.
   - TSC Procedure PEP EN-1, “Plant Accident Mitigation Diagnostic Aids and Guidelines,” was revised to include guidance on train separation.
   - The operators on FCV-495 and FCV-496 were upgraded to allow for remote manual operation from the control room.

- Other systems were reviewed for similar problems dealing with the generic implications of this issue.

The licensing basis impact evaluation (LBIE) performed to address the changes to the UFSAR and EOP was reviewed at the time of the NRC Design Inspection. PG&E continues to believe that the LBIE and attached safety evaluation conform to DCPP procedural requirements, and correctly conclude that these changes do not constitute an unreviewed safety question (USQ). The bases for this conclusion, as described in the completed LBIE, are as follows:

- The changes do not effect the design of any system or the ability of the systems to perform their safety functions.
- The changes do not affect assumptions made in the UFSAR accident analysis, nor the results of these analyses.
- The use of operators and the TSC personnel to assess the most reliable UHS lineup (ASW/CCW trains) for long term operation and to change the lineup as necessary in response to a single failure is acceptable. Indications of a single failure and system conditions are available, response can be made in an acceptable time frame, and procedures are in place to perform the necessary/appropriate operations.

PG&E will be working with Nuclear Reactor Regulation and Region IV to expeditiously resolve the USQ issue.

4. ***IFI 50-275/97-202-04:*** *ASME Section XI testing of ASW pumps (Section E1.2.1.2.f)*

Item Description *- The ASW pumps are tested to a specific point on the pump performance curve to establish the acceptance criteria. The specific point selected for the test requires throttling of the CCW heat exchanger ASW outlet valve of the opposite train (the pump is tested through the cross-tie to demonstrate adequate performance for the most limiting condition) to meet configuration requirements for the test. If the surveillance test is being performed as post maintenance testing (PMT), it could result in both the ASW pump and the opposite heat exchanger being inoperable at the same time (the heat exchanger is declared inoperable when its outlet valve is throttled). The team considered that rendering the CCW heat exchanger inoperable by throttling of the ASW outlet valve every time the surveillance test was performed was an undesirable practice, and that test modifications would correct this problem. DCPP initiated AR A0443221 to either (1) obtain relief from Section XI to allow testing the pump at various flow rates or (2) re-baseline the test reference flow rate to a higher value so that the heat exchanger outlet valve does not need to be throttled from its normal position.*

Response – A relief request was submitted in PG&E letter DCL-97-210, “Inservice Testing Relief Request P-RR5 - Auxiliary Saltwater Pump (ASWP) Performance Using Evaluation of Pump Curves,” dated December 12, 1997.

Approval of this relief request would allow ASW pump testing using an evaluation of pump performance compared to pump curves in lieu of a reference value as required by Operation and Maintenance Part 6, "Inservice Testing of Pumps in Light-Water Reactor Power Plants," paragraph 5.2.(b). Testing in accordance with this relief request would eliminate the need to adjust the CCW heat exchanger outlet throttle valve resulting in the heat exchanger being declared inoperable.

5. ***URI 50-275/97-202-05:*** *Discrepancy in Design Documentation (Sections E1.2.1.2.g, E1.2.3.2.e, E1.3.3.2.a, E1.3.3.2.d*

   Item Description (Example 1) *- The team reviewed the ASW system piping schematic 102017 sheets 3 and 3B, Revision 83, DCM S-17B, DCM M-46, "Piping Pressures, Temperatures, and Operating Modes," Revision 23, and calculation M-784 to verify the piping design pressure and temperature classification for the discharge lines from the pump to the CCW heat exchanger and from the CCW heat exchanger to the ocean. The team determined that the pressure and temperature classification as determined in M-784 were acceptable. However the temperature classification in DCM S-17B did not reflect the classification in M-784. DCPP initiated AR A0438253 to revise DCM S-17B to reflect the classification in M-784.*

   Response - DCM S-17B, "Auxiliary Saltwater System," is being revised per Action Request (AR) A0449058. The temperature and pressure classification for the ASW system will be corrected in this revision which will be implemented in conjunction with DCP M-49386 by June 1, 1998. This condition is considered to be an isolated problem with no generic implications since the correct information regarding pressure and temperature classification for the ASW system is provided in DCMs M-46, "Piping Pressures, Temperatures, and Operating Modes - Unit 1" and M-71, "Piping Pressures, Temperatures and Operating Modes."

   Item Description (Example 2) *- TS 3/4.5.5, page 3/4 5-11, RWST Surveillance Requirements, describes verifying the RWST temperature to establish operability during low outside ambient temperature conditions. However, TS bases 3/4.5.5, page B3/4 5-7, only mentions RWST volume and boron concentration as a requirement for operability. As indicated in the UFSAR and surveillance procedure STP R-20, temperature is verified along with boron concentration when performing surveillance of the RWST. This issue does not constitute a safety concern and the licensee will track this issue for correction as part of a planned effort to standardize the DCPP TS.*

   Response - Refueling water storage tank (RWST) temperature will be added to TS 3/4.5.5 Bases in conjunction with the DCPP Standard Technical Specification submittal. The discrepancy between TS 3/4.5.5 and its Bases occurred in conjunction with the implementation of License Amendment 101/100. Since LAR 94-06 (DCL-94-177, "Revision of Technical Specifications 3/4.1.2.5, 3/4.1.2.6. and 3/4.5.5 - RWST Allowed Outage Time

and Solution Temperature") proposed the elimination of RWST temperature from TS 3/4.5.5, reference to RWST temperature was removed. However, the NRC did not approve the deletion of the RWST temperature. Consequently, the RWST temperature remained in the TS, but the Bases approved by the NRC did not contain information on the temperature since it was proposed for deletion. Based on this unique cause, this finding is not considered to represent a generic concern regarding consistency between the TS and their Bases. Information regarding the RWST temperature will be added to the ITS Bases as part of the response to a request for additional information associated with Section 3.5 of the ITS. This request is expected to be received in approximately March 1998, with the information submitted approximately 30 days following the receipt of the request.

Item Description (Example 3) *- The team noted a discrepancy in DCM S-12, Section 4.3.1.g, which provided a description of the initiating signal for the CS system. The DCM section described only the "P" signal for automatic actuation of the CS system. According to UFSAR Chapter 7 and Logic Diagram 4014233, a coincident "P" and "S" signal is required to initiate automatic actuation, which is consistent with the design documents. This discrepancy has no safety impact. The issue involves an inconsistency between the design criteria document and the UFSAR. The licensee concurred and noted that AR A0438244 resolution will correct the DCM.*

Response - PG&E agrees with the inspection team that the statement in DCM S-12, "Containment Spray System," does not clearly identify what is really required for the containment spray (CS) system actuation and that the DCM requires enhancement. Both the DCM and the UFSAR have been revised as necessary to clearly identify the requirement of coincidental "S" and "P" signals for the automatic actuation of the CS system.

It is believed that the above discrepancy is the result of an assumption that the "P" signal would not be present without the "S" signal. This was based on the fact that conditions that cause the "S" signal (high containment pressure) would have to be present for the "P" signal parameter to exist (high-high containment pressure). As a result of this assumption, only the "P" signal was discussed in DCM S-12 as being required to actuate the CS system. As the system was always designed and maintained with both signals required, there is no safety impact with respect to this discrepancy. This discrepancy is believed to be an oversight and is considered to have no generic implications.

Item Description (Example 4) *- UFSAR Section 6.2.3.5.3, Spray Additive Tank Instrumentation, states that two alarms are provided to announce that the SAT solution has been exhausted. Based on a verification of control room annunciator layout drawing 500808 and the as-installed condition, only one alarm exists which is on window group PK01. Also, contrary to the UFSAR description, this alarm is to announce that the TS level of 60% in the SAT has been reached, instead of being exhausted. This discrepancy also affects Instrument Schematic 102033 Sh. 18 and DCM S-12, par. 4.3.9.1. The licensee concurred with this discrepancy and issued AR A0442941 to*

revise the UFSAR, Instrument Schematic and DCM S-12. The licensee does not consider that a tank LO-LO alarm is necessary for CS pump protection since emptying of the SAT and injection of gasses into the system will not have an adverse effect. Therefore, the existing design which consists of one alarm, provides sufficient information to evaluate the condition of the SAT in accordance with system design and the TS. The licensee plans to document their technical review of this issue in their safety evaluation that will be performed to revise the UFSAR.

Response - Instrument Schematic 102033, Sheet 18, was reviewed and determined to be correct as shown, with no further action necessary. DCM S-12 and UFSAR Section 6.2.3.5.3, will require revision to clarify the description of the spray additive tank alarms. ARs A0449235 and A0442941 have been initiated to revise the DCM and UFSAR, respectively. These revisions will be completed by February 27, 1998.

While each of these examples may have no specific generic implications, the overall question of their cumulative effect was examined. Because they are unrelated to each other and do not have safety significance, they have no overall cumulative impact on plant safety. Nonetheless, as part of PG&E's Licensing and Design Basis Alignment Program (LDBAP) to examine and improve the consistency of DCPP and its licensing and design basis, PG&E is reviewing the UFSAR and related documentation. In addition to correcting the identified discrepancies, the review effort will continue to examine both the individual findings and the cumulative impact of those findings on our confidence that the plant meets the requirements established in its design and licensing basis. Further actions will be taken should trends indicate that discrepancies might lead to loss of safety function capability. This review will be completed by October 31, 1998. Furthermore, the DCPP Corrective Action Program requires consideration of potential generic aspects of identified problems.

6. ***URI 50-275/97-202-06:*** *Availability of an Alternate Flowpath for the ASW System Section (Section E1.2.1.2.h)*

Item Description *- The ASW pumps for each unit have separate bays from which they take suction. As per UFSAR Section 9.2.7.2.3, "Each unit's pair of ASW pumps share a common traveling screen to remove floating debris from the incoming seawater. If the common screen for a unit becomes clogged with debris, seawater may be valved to the ASW pump bays from the unit's circulating water pump bays." The traveling screens at DCPP are designed as Class II, and are, therefore, neither seismically qualified or supported. The team determined that there is a potential for the screen to fail during a seismic event and restrict flow to the ASW pumps. The demusseling line flowpath is not tested or maintained on a routine basis to demonstrate its*

availability as an alternate flow path. The valves in the flowpath, however, are exercised to demonstrate their operability. The team identified that the inability to demonstrate an acceptable flowpath for ASW pump suction did not conform to the recommendation contained in GL 89-13. DCPP initiated AR A0443544 to reevaluate the need for testing or inspection of the flowpath. The team considered the fact that the UFSAR required flowpath was not being properly maintained (i.e., not in the maintenance rule) or tested to be contrary to the intent of GL 89-13 and a weakness in the licensee's program.

Response – PG&E has reviewed the design basis for the demusseling lines, and has determined that they are not a required redundant ASW flow path. Therefore, the demusseling lines were not considered for maintenance and/or testing in conjunction with the DCPP Generic Letter (GL) 89-13 Program.

The Operations staff can take several actions in the case of a loss of suction to an ASW pump. Abnormal Operating Procedure AP-10, "Loss of Auxiliary Saltwater," directs operators to first start the non-operating ASW pump for the affected unit. If that is not effective, then the operators are directed to utilize the standby pump from the opposite unit through the Unit crosstie valve, FCV-601. FCV-601 is seismically qualified and is Design Class I. It is designed to provide local manual or remote operation. Only if this action is ineffective are the Design Class II demusselling valves utilized to provide a suction flow path for the ASW pumps.

The demusseling piping and valves were specifically designed to support the heat treatment demusseling operation. In addition to this design function, they can provide a flow path to supplement flow in the event of severe screen clogging. Since the flowpath can only be established using Design Class II power and air, and there is no provision for manual opening of the valves, there is no provision in the design to ensure that the demusseling flow path can be placed in service under all plant conditions or after a seismic event. The absence of Design Class I features supports the conclusion that the demusseling flowpath was never intended to be a required redundant ASW flow path.

Enclosure 1 of the GL 89-13 states: "Redundant and infrequently used cooling loops should be flushed and flow tested periodically at the maximum design flow to ensure that they are not fouled or clogged. Other components of the service water system should be tested on a regular schedule to ensure that they are not fouled or clogged…" During the preparation of the GL 89-13 response, the demusseling lines and valves were not considered part of the safety-related service water system boundary. The demusseling line is not considered a "cooling loop" and, as such, would not meet the criteria for requiring flushing or testing as described in Enclosure 1 of the GL.

In summary, the demusseling flowpath was not included in the scope of the PG&E response to GL 89-13 because it is not a "required" fully redundant flow path for the ASW system. This is consistent with the design and licensing basis for this flow path, and PG&E believes that this should not be

considered a weakness in the PG&E GL 89-13 Program. Nevertheless, PG&E recognizes the value in ensuring the viability of the alternative flow path provided by the demusseling lines. Thus, PG&E currently performs periodic stroke testing of the demusseling valves. In addition, to evaluate the potential for biofouling or siltation of the demusseling flow path, PG&E will inspect one of the Unit 2 demusseling lines in conjunction with planned valve maintenance during the upcoming Unit 2 eight refueling outage (2R8) . Based on the results of the inspection, the need for a maintenance or testing program for the demusseling flowpath will be evaluated. This evaluation will be completed within 90 days of the completion of 2R8. The 2R8 is expected to be completed on approximately March 20, 1998.

PG&E's program in response to the NRC's 10 CFR 50.54(f) letter regarding adequacy and availability of design bases information (LDBAP), is examining other systems and will provide additional assurance that required functionality is available and covered by appropriate procedures. Any further actions required will be determined based on the results of that program. This program will be completed by October 31, 1998.

7. ***URI 50-275/97-202-07:*** *EDG transient analysis computer simulation study (Section E1.2.2.2.a)*

Item Description *- Paragraph 4.3.1.j of DCM S-21 stated that, "Each diesel-generator set is designed so that at no time during the loading sequence will the frequency decrease to less than 95 percent of nominal frequency. [R.G.1.9]." Paragraph 4.3.1.n stated that "The diesel-generator sets are designed to ensure that nominal frequency is restored within 2 percent of nominal in less than 40 percent of each load sequence time interval. [R.G.1.9]." Regulatory Guide 1.9 Revision 1 revised the 40 percent criteria to 60 percent but the DCM did not reflect this allowance. UFSAR section 8.3.1.1.13.1 has similar descriptions of capability. When the team questioned the licensee as to their commitment for bus frequency and recovery time the licensee pointed out that EDG loading had been discussed with the NRC in PG&E Letter DCL-85-132, dated March 29, 1985. In that letter, the licensee described how testing demonstrated that their equipment met "the intent of" Safety Guide 9 or Reg Guide 1.9 Revision 0. The licensee also pointed out that it was not clear from docketed correspondence that the NRC responded to their 1985 letter about "intent of" since the original SAR indicated that Reg Guide 1.9 was met.*

The team reviewed calculation 215-DC, Revision 1 dated December 26, 1996, "EDG Loading Capability Study without KWS Relay." In this study, a computer simulation was used to analyze the machine's transient responses. The results for four of the six diesel generators showed the frequency dropping to 56.8 Hz. or slightly below the 57 Hertz minimum criteria during design basis loading. The frequency dip occurred during the initial load block when none of the ECCS motors were loaded, and the only load on the

diesels were the 480 volt transformers. Also, during this initial load block, one machine had a frequency recovery time of 2.54 seconds, which slightly exceeded the 2.4 second (60%) criteria of NRC Regulatory Guide 1.9. The Integrated Test of Engineered Safeguards and Diesel Generators (Surveillance Test Procedure STP M-15) conducted on the diesels to monitor their performance, however, do not show any dip in frequency below 57 Hz. or recovery time greater than 2.4 seconds. This difference between the computer study and actual tests was determined to be due to the slow governor response modeled in the analysis. The study also showed that for the non-design-bases case when three motors were loaded simultaneously the frequency dipped to 55.68 Hz.

The team's review determined that the computer simulation study results and EDG design requirement for transient loading were not well documented and led to confusion during the inspection. DCPP initiated AR A0444243 to evaluate current system capabilities, to resolve the discrepancies in their commitment to EDG response transient loading, and to revise calculation 215-DC as necessary.

Response - During the NRC Design Inspection, PG&E provided the inspection team with specific responses to questions related to Calculation 215-DC and compliance with Safety Guide (SG) 9 and Regulatory Guide (RG) 1.9, Revision 1. These responses are documented in PG&E files as Chron 234219. In order to clarify the basis for DCPP's compliance with SG 9 and RG 1.9, Revision 1, PG&E will revise DCM S-21, "Diesel Engine System," and Calculation 215-DC. The DCM revision will define the acceptance criteria for transient frequency and voltage during the emergency diesel generator (EDG) loading sequence. The revision to Calculation 215-DC will clarify how the combination of testing and simulation results demonstrate compliance with SG 9 and RG 1.9, Revision 1. The calculation revision will also clearly categorize the results as design basis, special studies, or outside design basis. Revisions to DCM S-21 and Calculation 215-DC, will be completed by February 28, 1998.

The LBIE performed in conjunction with the change to UFSAR Subsection 8.3.1.1.13.1, dated April 23, 1997, which documented both field test data and simulation data, provided a technically sound basis for its conclusions. However, a recent review of this safety evaluation conducted as part of responding to the inspection team's questions, concluded that additional detail should be added to address the 50.59 questions. AR A0446633 was initiated to address this weakness and the LBIE will be revised and reviewed/approved by the Plant Staff Review Committee (PSRC) by April 30, 1998.

In addition, PG&E will submit a letter to the NRC discussing the inaccuracies in DCL-85-132 dated May 29, 1985, "Diesel Generator Capability," and documenting the basis for compliance with SG 9 and RG 1.9, Revision 1. This letter will be submitted to the NRC by May 30, 1998.

The issues addressed in this URI apply to all six EDGs and the corrective actions will encompass the generic implications for the entire set of EDGs. The additional scrutiny applied to the 50.59 evaluation was due to the heightened awareness caused by on-going efforts to strengthen the 50.59 process. No other generic aspects have been identified.

8. ***IFI 50-275/97-202-08:*** *Control of Calculations (Section E1.2.2.2.c, E1.2.2.2.i)*

Item Description

Example 1 *- The team also determined from review of calculation 195A-DC in conjunction with DCNs DC1-EE-47513, 45797 and 47195, that the current as built settings for TOL for ASW system motor operated valves 9001A and 9001B and flow control valves FCV-495 and 496 were included in the DCNs and not updated in calculation 195A-DC. AR A0444411 was initiated by DCPP to incorporate the DCN data in a revision to calculation 195A-DC. The team discussed with the licensee their controls for calculations. Procedure CF3.ID4, "Design Calculations," Revision 2, requires that calculations affected by a design change be identified and revised prior to closure of the design change package. The procedure does not however, require that calculations that are made obsolete by a change be automatically archived or made historical. The licensee's position is, that these superseded calculations served their purpose of forming the basis for the previous design and through other controls engineers are made aware of the current calculations. During the course of this inspection, the team had difficulty determining the most current calculations that supported the system design. The licensee's program depends heavily on people to remember the calculational history.*

Example 2 *-The status of calculations was confusing. Specifically, there are situations where limited scope calculations (i.e., smaller calculations) were performed. Data in these smaller calculations may supersede information in a larger calculation. There is no periodic updating of the major calculations to incorporate the collected small revisions. This same condition was also true for other functional reviews discussed elsewhere in this report.*

Response (Examples 1 & 2) - PG&E failed to fully explain the Calculation Program requirements to the inspection team. Specifically, Procedure CF3.ID4, "Design Calculations," Section 5.4.5 provides an exception for "master calculations that are updated on a scheduled basis" or periodically updated calculations. It states that these periodically updated calculations do not have to be in "Final" status when the DCP is closed provided that "the calculation for the specific design has been approved final and the structure, system, or component is not placed in service in an unanalyzed condition."

In addition, Calculation 195C-DC *(Note - the correct calculation number is 195C-DC instead of 195A-DC as stated in the IR)* is a master calculation periodically updated per Electrical Engineering Work Instruction EE-9. The master revision tracking AR for Calculation 195C-DC update is AR

A0303199. All three design change notices (DCNs) identified by the inspection team are listed in this tracking AR. Additionally, the setpoint change calculations were approved as part of these DCNs. PG&E believes that a more thorough explanation would have led to agreement on the adequacy of calculation controls relative to these specific changes.

Nonetheless, PG&E believes that the program should be enhanced and will take the following actions to address the specific concerns noted in Examples 1 and 2:

1) Revise Calculation 195C-DC to incorporate all design changes by March 2, 1998.

2) Revise Procedure CF3.ID4 to enhance the calculation process as follows:

   - Include the AR numbers of the tracking ARs for master calculation updates in the Design Calculation Index (DCI) "Remarks" field so that the user is alerted to the existence of a recently approved calculation not yet updated in the master calculation.
   - Include a requirement that when a calculation is revised or used for a design change, the user shall review the calculation package (and other calculations affected by the work in progress) for the current status and update the status on the calculation in the DCI when necessary.
   - Include a requirement to update the master calculations within 120 days of completion of a refueling outage if there any changes to the calculation.

   This revision will be completed by May 31, 1998.

3) During knowledge transfer activities associated with the transfer of engineering activities to the site, key calculations will be identified and reviewed by engineering, at which time calculation status changes will be made as appropriate. This activity will be completed by December 31, 1998. This will update several hundred of the most actively used and important calculations. PG&E has plans to update the status of the remainder of the approximately 35,000 calculations related to DCPP design only when they are used as discussed in 2 above.

While the above actions aimed at addressing the weaknesses in the process for controlling calculations identified by Examples 1 and 2 are not likely to resolve other existing unidentified calculational discrepancies, there are no indications that any safety functions have been impacted. Hence these actions are considered to be adequate to deal with the programmatic issues. In conjunction with our normal problem identification and resolution process, which will assure future identified problems are tracked and closed in an appropriate manner, these actions should be sufficient to preclude the emergence of significant calculation related issues.

9. ***IFI 50-275/97-202-09:*** *Review of Battery Charger Settings (Section E1.2.2.2.d)*

   Item Description *- The vital battery chargers are sized by calculation 236A-DC, and the current revision of this calculation takes credit for a maximum charger capability of 110% of the full load rating (440 amps). Again as per UFSAR Sections 8.3.2.2.1.4, 8.3.2.2.1.2, 8.3.2.2.2.4 and DCM No. S-67 Section 4.3.3.1 for Battery Chargers, the chargers are set at sufficient capacity to carry loads up to 110 percent of its 400 ampere rating and are set to current limit at 110% of rated output current. However, Maintenance Procedure MP E-67.3A, "Routine Preventive Maintenance of Station Batteries," Section 7.19.6 sets the "current limit to 430 (425-435) Amps by adjusting P5 on the Current Control Module." At this present setting of 107.5%, the battery charger has adequate capability to supply the DC loads for analyzed accident scenarios. The current available to recharge a totally discharged battery is slightly reduced and this will lengthen the time required for recharge but will still be less than the twelve hours required by the UFSAR. The 107.5% battery charger setting is not in agreement with calculational assumptions. DCPP initiated AR A0441745 to reconcile the difference between the design bases and actual setting for the battery chargers.*

   The present battery float voltage setting is 135 Volts plus control tolerances that could allow it to be 135.9 Volts. This is 5 Volts above the TS 4.8.3.1.a.2 minimum requirement of "greater than or equal to 130 Volts on float charge." The Vendor manual from C&D, the battery Vendor, specifies a nominal float Voltage per cell of 2.20 to 2.25 Volts, which is 132 to 135 Volts for the 60 cell vital batteries. The team identified that a higher float voltage can tend to "bake" normally energized DC coils which may shorten the usable life of equipment. However, setting the float at 135 Volts can be beneficial since fewer equalizations would be necessary. DCPP issued AR A0444410 to reevaluate the float Voltage setting.

   DCPP selected a nominal equalize Voltage of 138 Volts. For equalizing charge, C&D recommends a range of 2.33 to 2.38 Volts per cell which is 139.8 to 142.8 Volts for 60 cells. The DCM S-67 defines the recommended DC System maximum operating limit of 139.8 Volts. Setting the equalize level at 138 Volts has no serious consequences except to reduce the effectiveness of the equalization. The team identified that DCPP's rationale for operating the battery outside of the battery manufacturer's float and equalization range recommendations was not clear. DCPP initiated AR A0444410 to review the setting for the battery float and equalize voltage.

   Response - Charger Output Current Setting - The concern raised by this IFI applies to the Revision 0 of the Calculation 236A-DC where the inverters are normally supplied by the battery through the respective charger resulting in a higher calculated charger load. After the inverter replacement project, the inverters are normally supplied from the 480V system as reflected in Revision

1 of the Calculation 236A-DC. The Revision 1 calculation shows the minimum battery charger load size as 316A. The purpose of the calculation is to establish that the sizing of the battery chargers is adequate to supply the existing DC connected loads and recharge the battery within 12 hours. The conclusions specify the minimum charger size of 316 amps, and therefore, the nominal setting of 430A (425-435A) in Maintenance Procedure E-67.3A, "Routine Preventive Maintenance of Station Battery Chargers," is acceptable. The UFSAR and DCM statements made in context were meant to describe battery charger capacity ratings. Although technically correct, the UFSAR and DCM statements could be inferred to be settings. PG&E will review and clarify the subject UFSAR and DCM statements by April 1, 1998.

Charger Float Voltage Field Setting - PG&E concurs with the inspection team that if the battery float voltage is set too high, it can tend to "bake" normally energized direct current (DC) coils. However, PG&E believes that the advantage of reducing the number of equalization cycles outweighs the negligible effect of the small delta (0.9 Volts) between the maximum set voltage and the maximum value of the manufacturer's recommended range. PG&E has recently revised the weekly Surveillance Test Procedure (STP) M-11A, Revision 12, "Measurement of Station Battery Pilot Cell Voltage and Specific Gravity," tolerance band of 135V +/- 1VDC to a tighter float voltage band of 135 +/- 0.5 volts as being conservative with respect to the field setting basis of 135V +/- 0.9 VDC. The basis for this field setting is found in STP basis document B-STP M-11A (Revision 0), paragraph 7.6. In addition, DCPP operating experience has shown that neither battery life nor capacity is affected by operation with the existing float voltage setting. We have also not noted an excessive number of normally energized DC coils failing due to "baking." Thus, the nominal float voltage field setting of 135 Volts, with the revised tolerance band, will be retained. AR A0444410 has been updated to document the rationale for the acceptability of this setting.

Charger Equalizing Voltage Field Setting - DCPP operating experience has shown that the charger equalizing voltage field setting of 138 VDC is adequate to restore the battery to nominal parameters. The 138 VDC field setting was selected to be below the recommended DC system maximum operating limit of 139.8VDC (DCM S-67, Section 4.3.1.g). The basis for the field setting is found in STP basis document B-STP M-11B (Revision 0), paragraph 6.13. Thus, the nominal equalizing voltage field setting of 138 VDC will be retained. AR A0444410 has been updated to document the rationale for the acceptability of this setting.

Since the existing battery current and voltage settings were determined to be appropriate and consistent with the applicable design bases, no generic considerations are involved in the issues addressed by this IFI.

10. ***URI 50-275/97-202-10:*** *Potential USQ and TS Adherence Associated with Containment Spray During Containment Recirculation (Section E1.3.1.2.b & c)*

Background - *In December 1991, the licensee discovered (LER 1-91-018) that the heat loads placed on the CCW system by two trains of RHR in the event of an accident with a loss of a single train of ASW would be unacceptable. The CCW system heat loads could be brought to within design limits by operating with only one train of RHR. Since the containment spray function is assumed by the RHR system during recirculation, PG&E believed that one RHR pump could not provide both adequate core cooling flow and containment spray flow simultaneously. No engineering calculation was performed to substantiate this belief, but it was felt to be an obvious conclusion based on pump curves and flow path resistances. Additionally, the licensee did not have a calculational basis for the original assumed ability of the RHR system to provide the containment spray function during the recirculation phase of the accident after a single failure occurred. Based on the new data (LER 1-91-018), PG&E initiated changes to the UFSAR to re-classify the containment spray function during recirculation as non-safety related, revised EOP E-1.3 to prohibit spray during recirculation with only one RHR pump in operation, and eliminate the UFSAR requirement to operate spray for a minimum of 2 hours. Westinghouse was requested to reevaluate the containment analysis to verify that two of the five containment fan coolers could remove the containment heat without the need to spray the containment using the RHR pump aligned to the containment sump. The team's review of the Westinghouse containment reanalysis is discussed in Section E1.2.1.2.c of this report (NRC IR 97-202).*

Item Description (Issue 1) - ***Original Safety Evaluations***

The problems noted by the Inspection Team in the safety evaluations performed to address the changes implemented in conjunction with LER-1-91-018 involved the following: The Operations Department did no safety evaluation for Revision 9 to EOP E-1.3 before it was issued because their screening was in error. Westinghouse did a safety evaluation for the revision after it was issued and concluded that there was no unreviewed safety question but recommended an UFSAR change. In spite of this Westinghouse recommendation, PG&E did not change UFSAR Table 6.3-5. The Westinghouse safety evaluation and the one associated with OE 91-15 performed by PG&E both failed to recognize that TS 3.6.2.1 required that the RHR system provide the long term containment spray function during the recirculation phase of the accident. Additionally, the newly discovered consequence of the single failure of an RHR pump could also be considered to be an unanalyzed consequence of the malfunction of equipment important to safety. The Inspection Team considered this issue to be a potential unreviewed safety question that should have been brought to the attention of the NRC for review when the LER condition was discovered.

Response - PG&E considers that the actions taken under the 50.59 process to declassify the CS function during the recirculation phase of a LOCA were appropriate, and that this change does not involve a USQ. The CS function during the recirculation phase of a LOCA is not required for CS operability by

either the licensing or design bases for DCPP. PG&E has interpreted the requirement to demonstrate the capability to spray containment using the RHR system as demonstrating that the valves connecting the RHR system to the containment spray rings can be opened. PG&E has evaluated the current configuration of DCPP Units 1 and 2 and believes that, based on the design of the system, the CS system is operable, and the TSs are not being violated since the evaluation demonstrates that recirculation spray can be performed given the worst case single failure assumption.

The screen for Revision 9 to EOP E-1.3, "Transfer to Cold Leg Recirculation," was based in part on the knowledge of the outcome of the prompt operability assessment, the preliminary investigation identifying NCR DC0-91-EN-N030, and the assessment of the evaluation used for the development of Operability Evaluation 91-15, "Component Cooling Water (CCW) System Temperature During Post-LOCA Reactor Coolant System Cold Leg Recirculation." However, based on the recent NCR and NRC Enforcement Conference on EOP changes without 50.59 reviews, current guidance would lead reviewers to conclude a 50.59 safety evaluation would be necessary.

Although Westinghouse recommended revision of Table 6.3-5 of the UFSAR, it was not revised because it reflects the sequence of events that takes place if EOP E-1.3 is followed with the occurrence of no single failures. It was the purpose of the table to show that switchover to recirculation mode could be accomplished in the required time, and not to illustrate the switchover timing of all single failure cases. Hence revision of the table to reflect the RHR train failure case was not appropriate, even though CS might not be used if one of the RHR trains were to fail.

As a result of the NRC inspection team's questions regarding the licensing and design basis of the CS function during the recirculation phase of an accident, PG&E prepared an integrated "white paper" (CS in Post-LOCA Recirculation Licensing and Design Basis History at the Diablo Canyon Nuclear Power Plant), and 50.59 safety evaluation. The "white paper" and 50.59 safety evaluation provide a single integrated picture of the bases and history, assembled from many references and the personal knowledge of individuals involved at the time. PG&E believes the plant design and its bases are consistent and valid, and that the changes made were appropriate under PG&E's 50.59 process. At the same time, it is clear that several errors and omissions occurred during the process of reviews and changes to the EOPs, UFSAR, and other documents. The "white paper" and 50.59 safety evaluation were reviewed by the PSRC on September 4, 1997, and the PSRC determined that the previous 1991 decision continued to be valid and that no USQ or TS change was required when the EOP change was made in 1991.

PG&E will be working with Nuclear Reactor Regulation and Region IV to expeditiously resolve the USQ issue. The required actions to address the identified errors and omissions are documented in AR A0442630 and have

been completed with the exception of a revision to EOP E-1.3 which will be completed by January 31, 1998.

Item Description (Issue 2) - 1997 Safety Evaluation

Because of the concerns expressed by the Inspection Team with regard to the change in the original design basis as to containment spray during post-LOCA recirculation, PG&E prepared a new consolidated safety evaluation. The new safety evaluation was titled; "10 CFR 50.59 Safety Evaluation for Reclassification of Containment Spray During the Recirculation Mode of Safety Injection As a non-safety-Related Function."

The Team determined that the licensee's response to Question 4 in this new safety evaluation involving the probability of occurrence or consequences of a malfunction of equipment important to safety previously evaluated in the SAR was marked "No." The limitations on the use of containment spray during recirculation with only one RHR pump in operation were never addressed in any revision of the UFSAR and therefore are a new ramification of the previously evaluated consequences of the single failure of an RHR pump. Additionally, as specified in 10 CFR part 50.59, a change to the facility or procedures specified in the UFSAR can not be made without prior Commission approval if it involves a change in the TS or is a USQ. The NRC is currently evaluating whether the licensee's change involved a USQ and whether a change to the TS should have been requested prior to the change. This item is included as part of URI 50-275/97-202-10, Potential USQ and TS Adherence Associated with Containment Spray During Containment Recirculation.

Response - The limitations on the use of CS during recirculation with only one RHR pump in operation were not addressed in the UFSAR because the accident analysis in the UFSAR states that no credit is taken for spray operation in the recirculation mode. UFSAR, Section 6.2C.4.2, containing a discussion of the current accident analysis, states "During the recirculation phase of post-accident operation, water can conceivably be drawn from the RHR heat exchanger outlet and sprayed into the containment atmosphere via the recirculation spray system. However, recirculation spray is not modeled in the COCO code in the analyses reported herein." With regard to containment analysis, the containment pressure remained below that assumed for the leakage and the temperature remained within the environmental qualification of equipment inside containment. Since there was no credit taken for using recirculation spray in the accident analysis, it was not considered necessary to include a discussion of the consequences of its unavailability, since there were no consequences.

Again, as discussed in the response to Issue 1 above, PG&E considers the actions taken under the 50.59 process to declassify the CS function during the recirculation phase of a LOCA were appropriate, and that this issue does not involve a USQ. Although use of recirculation spray is not required for accident mitigation, the capability does exist to establish recirculation spray

even in the event of the failure of an RHR train, meeting the TS requirements. Hence, the probability of occurrence or the consequences of a malfunction of equipment important to safety has not changed, and a no USQ conclusion is appropriate under the circumstances.

While PG&E believes that the correct evaluation conclusions were reached in the 1991/1992 process related to this change, a number of errors were made. The LDBAP review program, as mentioned elsewhere in this response, continues to examine functional requirements specified in the UFSAR and their implementation, and will provide confidence that potential errors in the processing of other problems and/or changes did not compromise the capability of systems or structures to perform their intended safety functions.

In addition, because of the more significant nature of this issue, PG&E will identify and examine other design basis related problems that were identified and reported on LERs in the last 10 years and resolved with a plant or procedure change, but for which no LAR was submitted. Any identified errors with the handling of these problems will be corrected, and their overall significance will be assessed to see if any further work beyond this effort is required to provide assurance that the plant's structures and systems can perform their intended functions. This program will be completed by December 31, 1998.

June 16, 1998

PG&E Letter DCL-98-071

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

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Commitment Change Summary Report

Dear Commissioners and Staff:

In accordance with the Nuclear Energy Institute's (NEI) "Guideline for Managing NRC Commitments," Revision 2, endorsed by the NRC in SECY-95-300, PG&E hereby submits the enclosed Commitment Change Summary Report for Diablo Canyon Power Plant, Units 1 and 2. The report provides a summary of the regulatory commitment changes that occurred during the period January 1, 1996, to December 31, 1997. The summary for each change includes identification of the source document(s), a description of the original and revised commitments, and a justification for the change.

The regulatory commitment changes described in the report were processed in accordance with the NEI guideline, and were determined to not require prior NRC approval. The report does not include commitment changes that are contained in 10 CFR 50.59 safety evaluation summary reports, or in other submittals previously transmitted to the NRC.

Sincerely,

Gregory M. Rueger

cc: Steven D. Bloom
Ellis W. Merschoff
Kenneth E. Perkins
David L. Proulx
Diablo Distribution

Enclosure

FSC/WEC/1392/A0450790

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

CONTENTS

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

1. INDUSTRY OPERATING EXPERIENCE PACKAGES

Source Document(s): PG&E Letter DCL-89-004, "Reply to NRC Inspection Report Nos. 50-275/88-26 and 50-323/88-24," dated January 6, 1989

Original Commitment

Operating experience packages should be developed on a system basis for use by the system engineers and design engineers.

Revised Commitment

PG&E uses action requests to record evaluations and track implementation of applicable industry operating experience.

Justification for Change

The action request (AR) subsystem within the plant information management system (PIMS) provides the packaging of operating experience information for the engineering staff. The AR is coded to the applicable system. Thus, any system or design engineer who has a need for operating experience information has access through the PIMS database. The intent of the commitment is not changed, and there is no reduction in commitment.

2. DCPP HOUSEKEEPING PROGRAM

Source Document(s): PG&E Letter DCL-90-119, "Reply to Notice of Violation in NRC Inspection Report Nos. 50-275/90-01 and 50-323/90-01," dated May 2, 1990

Original Commitment

The housekeeping program will be revised to include a Housekeeping Supervisor who will be given the appropriate authority to investigate, correct, and revise the housekeeping activities as required to achieve DCPP housekeeping goals.

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

Revised Commitment

Directors, supervisors, foremen, individuals, and area owners are responsible for plant and job site housekeeping.

Justification for Change

Subsequent revisions to Administrative Procedure AD4.DC2, "Plant Housekeeping Areas," changed the responsibility for housekeeping to section directors, crew foremen, and various others. This change in responsibility does not reduce the effectiveness of the plant housekeeping program and does not affect the intent of the original commitment.

3. PLANT WALKDOWNS BY SENIOR MANAGEMENT

Source Document(s): PG&E Letter DCL-88-236, "Reply to Notice of Violation in NRC Inspection Report Nos. 50-275/88-15 and 50-323/88-14," dated October 5, 1988

Original Commitment

The plant manager will assure that records (of plant walkdowns by senior management) are maintained for subsequent inspection. However, it remains PG&E's position that these are not quality records that must be archived.

Revised Commitment

The original statement of commitment was deleted from the procedure commitment database because the walkdown records are not quality documents.

Justification for Change

Administrative procedure AD4.ID1, "Housekeeping," and related procedures now provide an effective program for plant housekeeping.

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

4. GRINNELL DIAPHRAGM REPLACEMENT PROGRAM

Source Document(s): PG&E Letter DCL-92-086, Licensee Event Report 2-91-009-01, “10 CFR 100 Dose Limits Potentially Exceeded in the Event of a Design Basis Loss of Coolant Accident Recovery as a Result of Valve Leakage,” dated April 24, 1992

Original Commitment

Maintenance Procedure M-51.7, "Grinnell Diaphragm Valve Maintenance," will be revised to include vendor recommendations on diaphragm replacement frequency and bolt torquing for diaphragm valves.

Revised Commitment

Maintenance Procedure M-51.7, "Grinnell Diaphragm Valve Maintenance," has been revised to include vendor recommendations on diaphragm replacement frequency and bolt torquing for diaphragm valves. However, based on PG&E’s predictive maintenance program, changes to the Grinnell diaphragm replacement program, such as removing valves from the program or revising valve maintenance frequencies, are allowed without effecting a change to the commitment. These changes to the program will be appropriately evaluated and documented.

Justification for Change

Notwithstanding the guidance provided by the vendor, the commitment needed to be changed to provide PG&E the flexibility to modify the program based on specific considerations. These modifications and considerations include removal of certain valves from the program or changes in predictive maintenance frequencies based on plant component history, operational considerations, and engineering evaluations.

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

5. QUARTERLY SYSTEM ENGINEER STATUS REPORTS

Source Document(s): PG&E Letter DCL-88-236, "Reply to Notice of Violation in NRC Inspection Report Nos. 50-275/88-15 and 50-323/88-14," dated October 5, 1988

PG&E Letter DCL-89-004, "Reply to NRC Inspection Report Nos. 50-275/88-26 and 50-323/88-24," dated January 6, 1989

PG&E Letter DCL-89-100, "Reply to NRC Inspection Report 50-275/89-01 and 50-323189-01," dated April 20, 1989

Original Commitment

The system design engineer and plant system engineer shall develop a summary report on their assigned system on a quarterly basis. This report shall discuss significant unresolved problems including proposed action plans, status of outstanding design changes, nonconformance reports, quality evaluations, action requests, and INPO review or action items.

Revised Commitment

Quarterly system engineering reports are no longer performed. Therefore, this commitment has been deleted from the program.

Justification for Change

The original commitment was established to resolve concerns associated with the previous engineering organization in that design and system engineering had separate locations, corporate versus plant site, and had a weak interface. Thus, the quarterly system engineering report was developed to improve interaction and communication between the two organizations to focus on plant-related system problems together. The current engineering organization combines the design and system engineers into one organization at the plant site. Thus, the quarterly system engineering reports are no longer considered an effective tool.

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

6. ROVING FIRE WATCH DUTIES

Source Document(s): PG&E Letter DCL-91-249, Licensee Event Report 1-91-015-00, "Violation of Technical Specification 3.7.10 When an Hourly Fire Watch Patrol Was Not Performed Due to Inadequate Instructions," dated October 16, 1991

Original Commitment

Written instructions have been added to the fire watch round status logsheets stating (1) the hourly roving fire watch should first contact the senior fire watch on site when a problem arises that may delay the hourly fire watch patrol; (2) the senior fire watch on site will arrange to have a relief individual perform a partial or complete TS impairment inspection; (3) if a relief individual is not available, the senior fire watch on site shall contact the Shift Foreman and request an inspection of the TS-related fire barrier impairments by Operations shift personnel or by the shift industrial fire officer; and (4) if the senior fire watch cannot be contacted in a timely manner, the fire watch may call the Shift Foreman directly.

Revised Commitment

Written instructions have been added to the fire watch procedure and logsheet to instruct the fire watch to contact (call or page) the Shift Supervisor or Shift Foreman if there is a delay of 20 minutes or more in completion of the round. Failure to patrol areas that include fire system impairments is a violation of the equipment control guidelines.

Justification for Change

The original commitment implied that the roving fire watch was to inspect the impaired fire barriers, which is not the case. The duties of the roving fire watch have been clarified to establish a patrol of the fire areas that "contain" impairments as a compensatory measure (i.e., the roving fire watch is not required to inspect the impaired fire rated assemblies). The original statement was meant to describe the actions the fire watches should take when unable to complete his or her rounds within one hour. It was not intended to increase the scope of the hourly fire watch patrols to inspect impaired fire barriers.

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

7. APPROVAL OF OVERTIME RESTRICTIONS

Source Document(s): PG&E Letter DCL-93-070, Licensee Event Report 1-92-021-01, "Technical Specification 6.2.2 Overtime Restriction Violations Due to Inadequate Overtime Control Program," dated March 26, 1993

PG&E Letter DCL-96-061, "Reply to Notice of Violation in NRC Enforcement Action 95-279 (NRC Inspection Report Nos. 50-275/95-17 and 50-323/95-17)," dated February 23, 1996

Original Commitment

Personnel were informed that no overtime exceeding six days shall be approved without the Vice President - Diablo Canyon Operations and Plant Manager, or the Vice President - Nuclear Technical Services prior approval.

Revised Commitment

No individual shall work more than six consecutive days without the written preapproval from a manager. No individual shall work more than 13 consecutive days without the written preapproval from a vice-president.

Justification for Change

The commitment was changed to allow managers to approve authorizations to exceed work in excess of six consecutive days. Authorization at the manager level is not expected to result in a significant increase in the number of approvals. A new limit of thirteen consecutive days is being instituted. Written approval at the vice president level will be required to exceed this limit. This rigorous written authorization approval process will continue to provide assurance that employees are physically capable and mentally alert to perform their assigned activities in a safe and efficient manner. This change does not conflict with the DCPP TS limits on overtime.

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

8. PLANT STAFF REVIEW COMMITTEE (PSRC) REVIEW OF EVENT INVESTIGATION TEAM (EIT) REPORTS AND SPECIAL QUARTERLY MEETINGS

Source Document(s): PG&E Letter DCL-86-164, "Response to IEIR 50-275/86-14 and 50-323/86-15 - Notice of Violation," dated June 11, 1986

PG&E Letter DCL-87-136, "PGandE Management Actions to Maintain the High Level of Performance at DCPP," dated June 15, 1987

PG&E Letter DCL-89-004, "Reply to NRC Inspection Report Nos. 50-275/88-26 and 50-323/88-24," dated January 6, 1989

Original Commitments

A special PSRC meeting will be held once per quarter to assure DCPP is taking adequate overall corrective actions in response to identified problems. This special PSRC will overview the following to ensure application of lessons learned and that any trends are identified:

- Effectiveness of Technical Review Groups
- Trending of Nonconformance Reports and LERs
- Human Performance Evaluation findings (Ref. DCL-86-164)

PSRC will continue to perform quarterly reviews of the performance indicator trends and will focus on specific areas where additional actions may be needed. (Ref. DCL-87-136)

Review all EIT reports at PSRC and GONPRAC (General Office Nuclear Plant Review and Audit Committee) meetings to create management awareness of the corrective actions recommended by EITs and to ensure that management is aware of significant safety concerns. Implement a policy where GONPRAC and PSRC hold a joint meeting quarterly to discuss the status of significant industry and DCPP operating experience. (Ref. DCL-89-004)

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

Revised Commitments

The PSRC and GONPRAC (now NSOC, or Nuclear Safety Oversight Committee) no longer hold special quarterly meetings nor directly review Event Investigation Team (EIT) reports. Therefore, these commitments have been deleted.

Justification for Change

The PSRC determined that special PSRC meetings did not provide significant value and has discontinued the practice. The EIT reports are reviewed in essence when the PSRC reviews the associated nonconformance reports (NCR)s. Furthermore, EIT reports are sent to senior management for review, which provides for notification of significant safety concerns. The PSRC has revised its practice to review the NCRs approximately one month from the date of initiation. This review includes scope, schedule, and initial corrective actions. The PSRC also reviews the NCR for final approval of the root cause and corrective actions. Self assessments of corrective action effectiveness may be requested by the PSRC for significant problems. In accordance with its charter, NSOC reviews PSRC minutes and all nonconformance reports, and thereby continues to review issues, occurrences, or problems that have or could have a significant impact on safe plant operation.

9. PLANT MANAGEMENT REVIEW OF REGULATORY COMMITMENTS

Source Document(s): PG&E Letter DCL-88-265, “Reply to Notice of Deviation in NRC Inspection Report Nos. 50-275/88-25 and 50-323/88-23,” dated November 7, 1988

Original Commitment

To ensure regulatory commitments are reviewed with plant management in a timely manner, commitments that are scheduled to be completed within the coming two week period will be reviewed each Monday during the plant manager’s meeting. This review will focus management’s attention on regulatory commitments to ensure they are completed in a timely manner.

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

Revised Commitment

The Director, Regulatory Services, will review upcoming regulatory commitments and take steps to ensure that regulatory firm due dates are met.

Justification for Change

As an enhancement to the commitment tracking process, PG&E revised Administrative Procedure XI1.ID1, "Regulatory Correspondence Processing," to ensure that regulatory commitments are tracked and reviewed in a timely manner prior to their due date by the Director, Regulatory Services. This enhancement ensures that commitments with the potential to exceed their due dates are brought to management for attention.

10. SHIFT FOREMAN AND FIRE PROTECTION SPECIALIST RESPONSIBILITIES

Source Document(s): PG&E Letter DCL-96-068, Licensee Event Report 1-84-048-00, "Technical Specification 6.8.1.h Not Met Due to a Programmatic Deficiency," dated March 22, 1996

Original Commitment

Administrative Procedure OM8.ID2 requires the shift foreman and the fire protection specialist to be informed immediately of any discovered fire system impairment and to review any planned fire system impairment.

Revised Commitment

Administrative Procedure OM8.ID2, "Fire System Impairment," requires the shift foreman to be informed immediately of any discovered fire system impairment. OM8.ID2 requires the shift foreman and the fire protection specialist to review any planned fire system impairment.

Justification for Change

The original commitment was stated in error. The shift foreman is the single point of contact who must be informed of possible fire system impairments.

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

11. INDEPENDENT TECHNICAL REVIEWER (ITR) RESPONSIBILITIES

Source Document(s): PG&E Letter DCL-84-228, "Response to NRC Enforcement Action EA 84-42," dated June 15, 1984

Original Commitment

To further help assure the technical adequacy of plant procedures, Administrative Procedure E-4, "Procedures," was revised on June 11, 1984, to add the requirement to conduct an independent technical review of operating, emergency, testing, maintenance, chemical, and radiochemical procedures with substantial technical content. This review will be performed by a knowledgeable individual selected by the appropriate department head. The reviewer shall not be the author, but may be the author's line supervisor. The independent reviewer will be responsible (along with the author) for assuring that:

- The procedure will accomplish the desired results.
- Technical Specifications, cautionary notes, and other such references are clearly specified so that the user is not misled.
- Setpoints, valve numbers, limits, and other such information are correct.
- The procedure is clear and unambiguous.
- Technical Specifications and other license conditions are complied with.

The independent review shall be documented by the signature of the reviewer and a brief statement of the general nature of the review (for example, what was looked at, references used, whether the procedure was tried in the field). Independent technical reviews of subsequent revisions will be required only if the technical nature of the procedure is changed. The normal biennial review of a procedure is, in itself, an independent review and should serve as such unless major changes are made to the procedure. The independent review will not be performed for minor editorial changes.

The appropriate department head shall determine whether an independent technical review is necessary. The independent technical review will be documented on the procedure history form, which is attached to the affected procedure when presented for PSRC review. During the procedure review by the PSRC, the procedure sponsor will delineate any substantive changes to the procedure to the members of the Committee. Additionally, the Plant Manager has advised the members of the PSRC to review the procedures on the Committee agenda prior to the meeting.

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

Revised Commitment

(1) The sponsor and independent reviewer shall assure that new procedures or procedure changes will:

a. Accomplish the desired results.
b. Clearly specify TS, cautionary notes, and other such references so that the procedure user is not misled.
c. Contain correct setpoints, valve numbers, limits, and other such information.
d. Comply with TS and other license conditions.

(2) The independent review shall be documented by the reviewer's signature.

Justification for Change

The Final Safety Analysis Report Update, Chapter 17, establishes the qualifications and requirements for performing an independent technical review. It states in part: (a) Each procedure, program, test, or experiment, and changes thereto, shall be reviewed by an individual/organization other than the individual/organization who prepared the proposed document, but who may be from the same organization as the individual/organization who prepared it; (b) Individuals responsible for the above reviews shall be knowledgeable in the document subject area and shall meet or exceed the qualification requirements of Section 7 of ANSI/ANS 3.1, 1978, and shall be designated as qualified reviewers by the plant manager or his designee.

A brief statement of the general nature of the review was eliminated from the commitment. If clarification is needed as to what was reviewed or to explain any "no" answers on the licensing basis impact evaluation (LBIE) screen, the sponsor and independent technical reviewer (ITR) are to use the LBIE screen's remarks section for that purpose. Also, administrative procedures specify what the ITR must consider when performing a procedure review, which is being retained in the proposed commitment wording.

The reference to the normal biennial review of a procedure being an independent review was deleted. The ITR is expected to review each technical procedure revision against the TS requirements, as detailed in the revised commitment. In addition, the biennial review process has changed since 1984. Today, many procedures may be exempt from a biennial review if they are used at least once every two years. (Ref. NRC letter to PG&E, dated March 2, 1993, "Quality Assurance Program Description for Diablo Canyon")

All of the PSRC information in the original commitment was deleted. The sponsor documents significant change details on a procedure history sheet. Most procedures no longer require approval by the PSRC. (Reference NRC safety evaluation for License Amendments 117 and 115, for DCPP Units 1 and 2, respectively, dated October 25, 1996.) However, if required, the PSRC has the option of reviewing the significant changes delineated on the procedure history sheet or asking the sponsor to go through the changes verbally. Significant change details are always available to the procedure's approving authority, whether or not PSRC review is required.

12. STP M-26 SURVEILLANCE CHANGE FROM MONTHLY TO QUARTERLY

Source Document(s): PG&E Letter DCL-88-215, "Auxiliary Saltwater System Operability," dated September 13, 1988

PG&E Letter DCL-90-027, "Response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," dated January 26, 1990

Original Commitment

A monthly surveillance test STP M-26, "ASW System Performance Monitoring," is performed to further document that the ASW flow through the CCWS heat exchanger is sufficient to meet the acceptance criteria.

Revised Commitment

Surveillance Test Procedure (STP) M-26 has been revised from a monthly to a quarterly surveillance test.

Justification for Change

Marine fouling of the ASW system has been eliminated through implementation of continuous chlorination. This has eliminated biofouling that could develop in the ASW system during the surveillance interval. In the event that two heat exchangers are in service in accordance with TS 3/4.7.12, effective treatment can be provided by either running one ASW pump with two heat exchangers or by alternating chlorine injection from one train to the other on a periodic basis. Extending the test frequency will not subject the ASW system to additional fouling or mask any change in flow due to fouling since the chlorine residuals have eliminated living biota from the system, as verified during inspections per

COMMITMENT CHANGE SUMMARY REPORT
JANUARY 1, 1996 TO DECEMBER 31, 1997

STP M-235, “ASW Piping Inspection,” performed during the Unit 1 seventh and eighth refueling outages and the Unit 2 eighth refueling outage.

Inspections performed every outage of the ASW forebays have never shown sufficient silt accumulations that would impact pump flow, so STP M-26 is not needed to address bay siltation concerns.

Inspections per STP M-235 have never found a delamination or other failure of the ASW pipe liner that impacted system flow. The coating has never experienced a delamination failure in 20 years of service. Based on the DCPP operating experience, it is unlikely that there would be a sudden flow blockage of the ASW system that would need to be detected by a monthly, versus a quarterly, test.

Concerns about siltation of the cross-tie line are addressed both by a quarterly test and by the design of the train cross-tie (the horizontal section of the cross-tie is located 11 feet-8 inches above the normal ASW flow path). No siltation of this line was noted when it was inspected in the Unit 1 fourth refueling outage. The use of continuous chlorination prevents fouling of this line by limiting access of live larvae to the cross-tie line. A quarterly test should provide sufficient flushing, since the unit-to-unit cross-tie is flushed through FCV-601. By extension, there will be no increased risk of problems with the cross-tie line by extending the test frequency to quarterly.

The STP M-26 data were reviewed from 1993 to the present. No trends indicative of pipe fouling have been noted. Since there has not been a significant trend observed with monthly testing, it is not expected that there would be any impact due to quarterly testing.

September 28, 1998

PG&E Letter DCL-98-136

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

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
10 CFR 50.59 Report of Facility Changes, Tests, and Experiments
for the Report Period May 24, 1996 - March 28, 1998

Dear Commissioners and Staff:

Pursuant to 10 CFR 50.59, "Changes, Tests, and Experiments," enclosed is the safety evaluation report for Diablo Canyon Power Plant Units 1 and 2. The report primarily includes safety evaluations, termed licensing basis impact evaluations (LBIEs) by PG&E, prepared during the interval May 24, 1996, to March 28, 1998, which corresponds to the reporting interval for the Diablo Canyon Final Safety Analysis Report Update, Revision 12. In addition, a few LBIEs prepared as late as September 1, 1998, are included.

The enclosed report provides a brief discussion of the changes and a summary of the LBIEs for the following change categories:

- Facility Changes
- Temporary Modifications, Electrical Jumpers and Lifted Leads, Mechanical Jumpers and Bypasses, and Test Equipment
- Procedure Changes
- Tests and Experiments
- Equipment Control Guidelines
- FSAR Update Changes
- Other Changes

The Plant Staff Review Committee has reviewed the LBIEs and determined that the changes do not involve unreviewed safety questions or require changes to the Diablo Canyon Power Plant Technical Specifications.

Sincerely,

Gregory M. Rueger

cc: Steven D. Bloom
Ellis W. Merschoff
Gregory A. Pick (w/o enc.)
David L. Proulx
Diablo Distribution (w/o enc.)

Enclosure

RLR/1392

Enclosure
PG&E Letter DCL-98-136

10 CFR 50.59 REPORT OF FACILITY CHANGES, PROCEDURE CHANGES, TESTS, AND EXPERIMENTS

MAY 24, 1996 - MARCH 28, 1998

Pacific Gas and Electric Company
Diablo Canyon Power Plant, Units 1 and 2
Docket Nos. 50-275 and 50-323

A. FACILITY CHANGES

A. FACILITY CHANGES

A. FACILITY CHANGES

B. TEMPORARY MODIFICATIONS, ELECTRICAL JUMPERS AND LIFTED LEADS, MECHANICAL JUMPERS AND BYPASSES, AND TEST EQUIPMENT

C. PROCEDURE CHANGES

C. PROCEDURE CHANGES

D. TESTS AND EXPERIMENTS

E. EQUIPMENT CONTROL GUIDELINES

F. FSAR UPDATE CHANGES

F. FSAR UPDATE CHANGES

F. FSAR UPDATE CHANGES

G. OTHER CHANGES

G. OTHER CHANGES

A. Facility Changes

1. Restore the Fire Barrier Between Fire Area 4-B and 4-B-2
DCP A-050330, Rev. 0 (Unit 2) (LBIE Log No. 97-045)

The 2-hour fire barrier separating Fire Area 4-B and 4-B-2 is degraded because Pullbox BPG5 is partially embedded on the southside of the 2-hour plaster fire wall. Conduit k6944 is a safe shutdown circuit with a 1-hour 3M fire wrap on the north side of the fire barrier running along the north face of the plaster wall and connecting to Pullbox BPG5. To satisfy the requirement for a 2-hour plaster wall, provide a 2-hour pyrocrete enclosure behind the protuded Pullbox BPG5.

Safety Evaluation Summary

The degraded 2-hour fire rated plaster wall configuration was modified to meet the requirements of 10 CFR 50, Appendix R. This modification is required to maintain separate redundant trains of safe shutdown components, per Section IIIg of Appendix R.

2. Cathodic Protection for ASW Supply Pipelines
DCP C-049169, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-217)

This design change is for installation of a cathodic protection system for the existing Class I auxiliary saltwater (ASW) pipelines and new bypass ASW pipelines near the intake to reduce corrosion of the pipelines.

Safety Evaluation Summary

The cathodic protection system is largely buried, with most components not near the ASW pipes. The modification does not change any system interfaces and has no impact on ASW system capacity to perform its design function. The ASW system is not the cause of any FSAR Update analyzed accidents. Therefore, it is concluded that installation and operation of the cathodic protection system does not involve an unreviewed safety question.

3. Auxiliary Saltwater Bypass
DCP C-049207, Rev. 6 (Units 1 & 2) (LBIE Log No. 96-018)
DCP C-050327, Rev. 0 (Unit 2) (LBIE Log No. 97-179)
DCP C-050327, Rev. 1 (Unit 2) (LBIE Log No. 98-013)
DCP C-050327, Rev. 0 (Unit 2) (LBIE Log No. 97-157)
ASW Piping Bypass Project Letter, Rev. 0 (LBIE Log No. 97-007)

This design change installed a bypass around approximately 800 feet of Unit 1 and 200 feet of Unit 2 auxiliary saltwater (ASW) system piping. The project was initiated due to a concern that localized corrosion was occurring in the portion of the piping buried below sea level in the tidal zone outside the intake structure. In

addition, upgraded flow and temperature instrumentation was installed. The project was installed in phases. The project safety evaluation determined the change did not involve a unreviewed safety question. After interaction with the NRC, PG&E submitted a License Amendment Request (LAR 97-11) to resolve concerns with the analyzed potential for liquefaction in a small area below a portion of the Unit 1 piping. The LAR was later revised to apply only to Unit 1. The NRC has not completed their review of the LAR.

Safety Evaluation Summary

The installation of the bypass piping does not impact the ASW system design basis parameters. The rerouting and increased length of the bypass causes a small reduction of ASW flow, however the design and licensing basis functions of the ASW system are not impacted. The routing of a portion of the Unit 1 piping over an area that may be impacted by seismic induced liquefaction is conservatively included in the design. The LAR was submitted to allow the NRC to review the unreviewed safety question introduced into the Diablo Canyon FSAR Update by the liquefaction issue.

4. Intake Cove Revetment
DCP C-049310, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-015)

This DCP reinforced the rip rap revetment along the north shore of the intake cove, through the pumping of concrete into voids between the existing armor stones. This reinforcement is required in order to protect the soil surrounding and supporting buried auxiliary saltwater (ASW) bypass piping (installed per DCP C-49207) from damage associated with the tsunami-storm wave loading conditions defined in DCM T-9.

Safety Evaluation Summary

No 50.59 safety evaluation was performed for this design change, as the requirements of the safety evaluation screen were met. The safety evaluation was performed for an environmental evaluation as the performance of this work created discharges to the ocean that could impact PG&E's National Pollutant Discharge Elimination System permit. It was determined that the change did not involve an unreviewed environmental question.

5. Provide Pyrocrete Fire Barriers
DCP C-049339, Rev. 0 (Unit 1) (LBIE Log No. 97-160)

This modification involved the design of fire barrier materials, which protect redundant safe shutdown circuits from the effects of a fire. The Pyrocrete maintenance doors at Elevation 85 feet in the 12-kV switchgear room and the Transite barriers at Elevation 76 feet in the 12-kV cable spreading room will be

modified with an additional layer of Pyrocrete material to provide the required 2-hour fire rating.

Safety Evaluation Summary

The Pyrocrete maintenance doors at Elevation 85 feet in the 12-kV switchgear room and the Transite barriers at Elevation 76 feet in the 12-kV cable spreading room will be modified with an additional layer of Pyrocrete material to provide the required 2-hour fire rating to protect one train of redudant circuits for equipment per 10 CFR 50, Appendix R, Section III. G.2.

6. Unit 2 - Yard Pullbox: Install Fire Barrier
DCP C-050405, Rev. 0 (Unit 2) (LBIE Log No. 97-180)

During review of issues associated with yard pull boxes containing safe shutdown circuits, it was discovered that Transite panel separation barriers in Pull Boxes BPO 33, 33A, 33B, 33C, 43, 43A, 43B, and 43C were not qualified fire barriers. The Transite panels were not approved fire barriers. 10 CFR 50, Appendix R, Section III.G.2, requires a 3-hour rated fire barrier to be installed for one train of redundant circuits for equipment that is required to achieve and maintain safe shutdown and is located within the same fire area. As corrective action for Nonconformance Report N0001887, it was necessary to remove the unqualified Transite panels from the pull boxes and replace them with pre-cast 3-hour rated pyrocrete barriers to completely seal and separate the safe shutdown circuits in separate compartments within the pull boxes.

Safety Evaluation Summary

The 10 CFR 50.59 safety evaluation was performed because unqualified Appendix R fire barriers were replaced with qualified tested barriers. Although FSAR Update fire barrier descriptions are not particularly specific, the DCP was considered to be a modification to the fire protection system (FSAR Update Section 9.5). The design change brings fire protection in the Unit 2 yard pull boxes into conformance with NRC regulations and licensing commitments. The Unit 2 yard pull boxes fire barriers are not associated with initiation of any evaluated FSAR Update accident. The design basis accident is a pull box fire that is mitigated, not caused by, the subject barriers. The qualified pull box fire barriers ensure that at least one of the redundant safe shutdown circuits located in the yard pull boxes will be available for safe shutdown following a postulated fire. Combustible loading was not increased. New combustible materials were not added. The qualified pull box fire barriers ensure that a single fire will not affect both safe shutdown trains in the subject yard pull boxes. Installation of the barriers did not raise the possibility of a new equipment malfunction because the new barriers were fabricated outside the pull boxes and set in place using approved procedures.

7. Install Fire Barriers in Fire Area 20
DCP C-050339, Rev. 0 (Unit 2) (LBIE Log No. 97-014)

This design change modified the design of fire barrier materials that protect redundant shutdown circuits from the effects of a fire. An additional layer of Pyrocrete was added to the Pyrocrete maintenance doors in the 12-kV switchgear room and to the Transite fire barriers in the 12-kV cable spreading room to provide the required 2-hour fire rating. The modification was a required corrective action for Nonconformance Report N0001887.

Safety Evaluation Summary

This 10 CFR 50.59 evaluation was performed because FSAR Update Appendix 9.5A takes credit for the Pyrocrete barriers and Transite panels as providing the fire protection required for Fire Area 20. Prior to this modification, the subject barriers were not qualified. The new fire barriers are qualified by testing. The FSAR Update description was modified to reflect the change. Adding qualified fire barriers to protect redundant safe shutdown circuits does not affect probability, possibility, or consequences of any analyzed or unanalyzed accident or equipment malfunction. No equipment was modified; safety margins were not affected. The change was made to bring the fire protection in Fire Area 20 into conformance with NRC regulations. A two-hour fire barrier is required to meet DCPP's commitment for fire protection in the subject area. The combustible loading in the area is less than one hour.

8. Battery 13 Replacement
DCP E-049297, Rev. 0 (Unit 1) (LBIE Log No. 96-027)

This design change was to replace Battery 13 with a larger capacity battery. The major scope of work involved replacing 60 cells, fabricating a new step rack, modifying existing battery rack end restraints, and replacing feeder cable and inter-rack cables with 6 - #4/0 AWG cable. This design changed increased the battery capacity from 1800 amp-hr to 2320 amp-hr, which restored the both the vital 125-Vdc system and vital 120-V instrument ac system with positive load growth margins.

Safety Evaluation Summary

This design change did not affect the design basis of the 125-Vdc system. The larger capacity did not change/affect the electrical characteristic supplied to any of the 125-Vdc loads or cause any load to be operated outside their design or testing limits. The new Class 1E battery met the original design specifications for material and qualification (new qualification test was required). The new battery did not impose any new electrical load, and the existing battery charger, dc bus, or dc distribution panel/breakers did not require modification. No new operational or failure modes were introduced nor were there any changes

required to the Technical Specification Bases. The larger battery did increase the battery room floor loading and was accounted for and accepted by Civil engineering calculations. It also increased the amount of hazardous material since the larger battery uses about 60 gallons more sulfuric acid (electrolyte); this was evaluated for in the LBIE Environmental Protection Evaluation and is to be accounted for in the DCPP Hazardous Materials Business Plan.

9. Change the Tap Settings for the Vital MCC Transformers
DCP E-049321, Rev. 0 (Unit 1) (LBIE Log No. 96-037)
DCP E-050321, Rev. 0 (Unit 2) (LBIE Log No. 97-125)

Calculation 357-DC evaluated and provided the optimized transformer tap voltage settings for both minimum and maximum system voltage conditions under various modes of operation. Based on the calculation the vital distribution transformers (motor control center) taps were changed. The calculation and changes were a result of adding load tap changing (LTC) 230/12-kV transformers.

Safety Evaluation Summary

The choice of the tap setting is to provide adequate voltage at the terminals of Class 1E equipment under design basis accident conditions. The tap settings are not covered by Technical Specifications, and the safety functions are assured since these tap changes keep the 4-kV and 480-V buses within the design required voltage levels. Technical Specification 3.8.1 states. "… ensures that sufficient power will be available to supply the safety related equipment." The technical specification requirements and their bases' margins of safety are maintained by optimizing the tap settings for these transformers.

10. Replace SUT 11 With New Transformer Equiped With LTC
DCP E-049322, Rev. 0 (Unit 1) (LBIE Log No. 96-042)

This design change replaced the Unit 1, 230/12-kV startup transformer (SUT) 11 with a new transformer that uses an automatic load tap changing (LTC) device to control the voltage. This change resolved the short circuit withstand capability problem of SUT 11 that was discovered following the study that was completed as a result of the Unit 1 auxiliary transformer failure in October 1995. It also helped resolve the voltage problem that existed at the 4-kV and 480-V buses when supplied from the 230-kV startup source, which was not adequate under certain design basis operating scenarios to support the operation of safety-related equipment. This design change also replaced the existing 230-kV Disconnect Switch 211-1 with a circuit switcher that provides load break capability to allow removal of SUT 11 from service without deenergizing the 230-kV source.

Safety Evaluation Summary

The replacement of SUT 11 with a new transformer equipped with LTC for voltage control does not alter the original configuration of the electrical distribution system. It enhances the capability of the 12-kV and the 4-kV electrical distribution systems to have sufficient voltage for a successful transfer of the plant auxiliary loads to the startup source following a unit trip. This change also eliminates the potential for "double sequencing" of the 4-kV vital loads during an accident by providing adequate voltage to the 4-kV vital buses from the 230-kV source. The new transformer's design exceeds the short circuit capability requirement. So its malfunction is less likely than the old transformer. Malfunction of the LTC feature is the only new failure that was not a consideration for the old transformer. A failure modes and effects evaluation found that the possibility of a malfunction of the LTC is very unlikely and is no different than the possible failures already considered for the transformer. Malfunction of the LTC is monitored in the control room through voltage indication and annunciator alarm. Under the worst case scenario, during an accident, failure of the LTC in the boost position to maintain minimum voltage at the 4-kV vital buses would be detected by the second-level undervoltage relay and the 4-kV vital buses will transfer to the emergency diesel generators as per the original design.

11. Replacement of CFCU Timers
DCP E-049344, Rev. 1 (Unit 1) (LBIE Log No. 97-210)

All containment fan cooler unit (CFCU) timers in Units 1 and 2 were replaced with more accurate digital-type, Agastat DSC timers, along with internal wiring changes in the CFCU control circuits. The primary reason for the replacement was excessive drift in the old timers. The starting logic has also been modified such that CFCUs will auto-start with low speed under auto bus transfer conditions, regardless of the high/low speed control switch position.

Safety Evaluation Summary

The replacement DSC timers will provide equivalent (or better) performance than the existing timers. The starting logic modification makes the low speed start consistent with an existing administrative control. Therefore, this change does not involve an unreviewed safety question.

12. Battery 23 Replacement.
DCP E-050297, Rev. 0 (Unit 2) (LBIE Log No. 97-121)

Vital Battery 23 Replacement DCP/DCN implemented in the Unit 2 eighth refueling outage installed larger battery cells to accommodate increased dc loading from the new 120-Vac instrument uninterruptible power supply (UPS) and provide for future growth.

Safety Evaluation Summary

The replacement of Vital Battery 23 with larger cells increased the dc bus loading capability and supported the new larger UPS loads. There were no increases in the probabilities or consequences of any accidents previously evaluated in the FSAR Update as a result of this change. There were no unreviewed safety questions.

13. On-Line Replacement of Unit 2 SUT 21 and Its Disconnect Switch 211-2
DCP E-050322, Rev. 1 (Unit 2) (LBIE Log No. 97-183)
DCP E-050322, Rev. 1 (Unit 2) (LBIE Log No. 97-134)

The on-line replacement entailed removing the existing Startup Transformer (SUT) 21 and Disconnect Switch 211-2 and installing the new transformer and circuit switcher while Unit 2 was operating at power. During on-line replacement, the standby startup power to the Unit 2 12-kV startup bus was established by closing the 12-kV startup buses tie breaker. With the tie breaker closed, SUT 11 provided offsite power to both the Unit 1 and Unit 2 startup buses.

Safety Evaluation Summary

While the plant is in an on-line replacement configuration using one startup transformer, the design and licensing basis for the DCPP offsite power is not compromised since the shutdown power for Unit 2 in the event of an accident will be supplied by the available Unit 1 startup transformer while providing a standby power source to Unit 1. The operating instructions of Table I outlined in O-23 will be still applicable.

To handle an anticipated dual unit trip under the on-line replacement configuration, additional compensatory measures would be required, i.e., reduced 12-kV bus transfer, operating Morro Bay Power Plant (MBPP) Units 3 or 4 with a minimum voltage of 234 kV maintained at the DCPP 230-kV buses and availability of all six diesel generators to guard against a loss of offsite power. DCPP design basis allows reliance on the diesel generators for dual unit trips, since there is no common initiating event that would cause an accident in both units simultaneously.

Having a reduced 12-kV load transfer on both units provides additional offsite power margin to the vital buses in case of an accident at one unit or dual-unit trip. The reduced transfer does not result in an increase in probability or consequences of an accident.

There is an increased safety benefit and reduced risk in doing the replacement on-line since the plant configuration in Modes 1 through 4 is under much stricter and better control than in Modes 5 and 6.

There is no increased risk of plant operation while on-line replacement is being performed and the margin of safety as defined in the basis for any Technical Specification will be enhanced as a result of a better voltage control of the new transformer through its LTC. By maintaining a higher voltage at the 12-kV startup buses, the voltages at the 4-kV and 480-V busses will have better voltages providing additional margin of safety.

14. Replacement of CFCU Timers
DCP E-050344, Rev. 1 (Unit 2) (LBIE Log No. 97-211)

All containment fan cooler unit (CFCU) timers in Units 1 and 2 were replaced with more accurate digital-type, Agastat DSC timers, along with internal wiring changes in the CFCU control circuits. The primary reason for the replacement was excessive drift in the old timers. The starting logic has also been modified such that CFCUs will auto-start with low speed under auto bus transfer conditions, regardless of the high/low speed control switch position.

Safety Evaluation Summary

The replacement DSC timers will provide equivalent (or better) performance than the existing timers. The starting logic modification makes the low speed start consistent with an existing administrative control. Therefore, this change does not involve an unreviewed safety question.

15. Install Automatic Control for the LTC of SUT 21.
DCP E-050365, Rev. 0 (Unit 2) (LBIE Log No. 97-135)

This design change installed the automatic controls of the load tap changer (LTC) to the newly installed Unit 2 Startup Transformer (SUT) 21 which was used as a fixed tap transformer up to this point. The new SUT 21 and Circuit-Switcher 211-2 were installed in November 1997 under DCP E-50322. The installation of the automatic controls of the LTC put the system configuration for Unit 2 SUT 21 in the same configuration as that of Unit 1 Startup Transformer SUT 11.

Safety Evaluation Summary

The replacement of SUT 21 with a new transformer equipped with LTC for voltage control does not alter the original configuration of the electrical distribution system. It enhances the capability of the 12-kV and the 4-kV electrical distribution systems to have sufficient voltage for a successful transfer of the plant auxiliary loads to the startup source following a unit trip. This change also eliminates the potential for “double sequencing” of the 4-kV vital loads during an accident by providing adequate voltage to the 4-kV vital buses from the 230-kV source. The design of the new transformer exceeds the short circuit

capability requirement. So its malfunction is less likely than the old transformer. Malfunction of the LTC feature is the only new failure that was not a consideration for the old transformer. A failure modes and effects evaluation determined that the possibility of a malfunction of the LTC is very unlikely and no different than the possible failures already considered for the transformer. Malfunction of the LTC is monitored in the control room through a voltage indication and annunciator alarm. Under the worst case scenario, during an accident, failure of the LTC in the boost position to maintain minimum voltage at the 4-kV vital buses would be detected by the second level undervoltage relay and the 4-kV vital buses will transfer to the emergency diesel generators as per the original design.

16. Alternate Power Source to Spent Fuel Pool Pumps
DCP E-050381, Rev. 0 (Unit 2) (LBIE Log No. 97-216)

This design change adds alternate Class 1E power sources to spent fuel pool (SFP) Pumps 21 and 22. The alternate Class 1E power source will be available for use during electrical bus outages and maintenance periods and reduce the need for the use of temporary power jumpers to maintain one SFP pump available.

Safety Evaluation Summary

Providing an alternate Class 1E power source to the SFP pumps reduces the need for energized jumpers during outages. Previous jumper installation has caused increased wear and degradation of cables and terminations, as well as personnel hazards while installing the jumpers. Adding the alternate power source does not affect accidents or safety margin and therefore does not involve an unreviewed safety question.

17. Removal of Flow Controllers from Unit 1 AB and FHB HVAC System Supply and Exhaust Inlet and Downgrading Associated Flow Instruments from "Class I" to "Class IC"
DCP H-049326, Rev. 0 (Unit 1) (LBIE Log No. 97-205)
DCP H-050326, Rev. 0 (Unit 2) (LBIE Log No. 97-185)

This design change deleted automatic control of inlet air flow to the auxiliary and fuel handling building ventilation system fans. Controllers modulating inlet vanes of Fans E1, E2, S31, S32, E4, E5, E6, S1, and S2 to maintain predetermined flow from these fans are removed and they are replaced by manual pressure regulators that main inlet vanes at a predetermined (almost open) position. Also the change downgrades associated flow elements (sensors) from Class I to Class IC.

Safety Evaluation Summary

The design change simplifies operation and improves availability and reliability of the Unit 1 auxiliary building and fuel handling building HVAC systems. This change impacts the description in Section 9.4.2.2 of the FSAR Update. The change does not alter design intent and functionality and was determined to not involve an unreviewed safety question. Recommendation to remove the controllers is based on experience with the HVAC system operation.

18. Upgrade Debris Screens to Design Class 1
DCP H-050401, Rev. 0 (Unit 2) (LBIE Log No. 98-007)

The DCPP Operating License allows opening of the 48-in. containment purge valves during power operation. PG&E had committed in Supplement 9 of the Safety Evaluation Report to install debris screens on the containment side of the valves to ensure that debris will not lodge in the valve seat to prevent full closure of the valves in the event of an accident. This debris prevention function is safety related. However, currently, the Q-List, Design Criteria Memorandum (DCM) T-16, and DCM S-23A classify the debris screens as Design Class II, Seismic Category I. Design Change Package H-50401 upgrades the debris screens from Design Class II to Design Class I. This upgrade is required to ensure that the debris screens will perform their safety-related function.

Safety Evaluation Summary

The containment purge valves may be open during plant Modes 1-4 for purging of the containment. In the event of an accident, the valves must be able to fully close to maintain the integrity of the containment. The consequences of an accident evaluated in the FSAR Update is based on full closure of the isolation valves within the predetermined stroke time. This ensures that the off-site 10 CFR 100 dose guideline value is not exceeded. The safety-related function of the debris screens is to prevent debris generated during an accident from

lodging in the valve seat such that it may affect closure of the valves. Upgrading the design classification of the debris screens and associated components to Design Class I will ensure that this safety-related function can be fully met and that the consequences of an accident would not be increased.

19. Met Tower Instrument Upgrade
DCP J-049101, Rev. 1 (Unit 1) (LBIE Log No. 97-189)

This design change replaced the obsolete meteorological instrumentation on both the primary and backup meteorological towers. The supplementary measurement instrumentation is mounted permanently on top of the backup meteorological shack. This design change was implemented when the equipment was removed from service for its bi-annual calibration.

Safety Evaluation Summary

The design change upgrades the meteorological instrumentation to maintain the requirements of Regulatory Guide (RG) 1.97. The met instrumentation is nonsafety related, is used for monitoring purposes only, and is not part of any accident scenarios previously evaluated in the FSAR Update. The meteorological instrumentation does not interface with any equipment important to safety. All requirements required by RG 1.97 are maintained.

20. Safety Parameter Display System Replacement
DCP J-049123, Rev. 0 (Unit 1) (LBIE Log No. 96-005)

This design change removed and replaced the existing Unit 1 emergency response facility data system (ERFDS). The ERFDS/SPDS is being replaced to solve the following problems: (a) software errors exist which result from operational changes or latent software defects in the original B&W software, (b) parts are not available for hardware failures impacting system availability, and (c) ERFDS software changes can only be purchased at great expense from the original vendor.

Safety Evaluation Summary

The SPDS is functionally and spatially incapable of creating design basis events comparable to those evaluated in the FSAR Update. The replacement of the SPDS and the abandonment of the ERFDS tape function and use of the plant process computer function in the Technical Support Center and emergency operations facility do not introduce any new equipment, configurations, or hazards not previously evaluated.

21. Replacement of Plant Vent Gross Gamma Monitors RM/RE-29
DCP J-049193, Rev. 0 (Unit 1) (LBIE Log No. 96-022)
DCP J-050193, Rev. 0 (Unit 2) (LBIE Log No. 96-023)

This design change replaces the entire analog RM-29 radiation monitoring channel with more modern digital equipment. Components included in this change include the local detector/preamp assembly (RE-29) and control room readout module (RM-29). The local indicator (RI-29A) is no longer required and will be permanently removed. This design change also installs a rigging support structure local to the detector assembly to add in disassembly of heavy lead shields during calibration activities.

Safety Evaluation Summary

This design replaces the existing obsolete RM-29 radiation monitor with a more reliable digital radiation monitor having the same range, functionality and peripheral interfaces. Removal of RI-29A (referenced in FSAR Update Chapter 2) is acceptable as it is not required per RG 1.97 and does not impact the capabilities of RM-29. The rigging support will be seismically qualified to meet seismically induced systems interaction requirements. This design change does not affect Technical Specifications, Emergency or Security Plans, Effluents, Environmental Protection, Fire, or Quality Assurance Programs.

22. Connect PGA Panel Alarm and Condenser DP Signal to Control Room
DCP J-049218, Rev. 1 (Unit 1) (LBIE Log No. 96-038)

This design change replaced existing local condenser delta-P pressure indicators on the generator auxiliaries (PGA) panel with indicating transmitters. The transmitter signals are processed by a new local panel, PK011, and sent to the plant process computer (PPC). The PPC provides control room indication of the condenser delta-P signal and alarm capability to the main annunciator system (MAS). Individual alarm signals from the PGA panel were transmitted to the MAS by a new remote multiplexer in PK011.

Before the modification, individual PGA panel alarms and condenser DP indications were available only locally. A grouped alarm from the PGA panel was input to the MAS for display in the control room. On receiving the grouped alarm, an auxiliary operator was dispatched to identify the specific generator alarm. The associated delay could have led to a unit trip or generator damage.

The safety-related portion of the modification installed raceway supports in the auxiliary building.

Safety Evaluation Summary

The safety evaluation was performed because FSAR Update Section 3.10.2.9 described the MAS as seismically qualified. The new remote multiplexer does not require seismic qualification. Information provided to the control room by the nonsafety-related instrumentation in PK011 is not required for safe plant shutdown or to mitigate the effects of an accident. Isolation is provided where needed to prevent a failure in the multiplexer from degrading operation of the MAS, PPC, or main condenser. The FSAR Update was changed to clarify that the nonseismic portion of the MAS will not adversely affect operation of the seismic portion. Verification activities ensured that no rebar was cut or damaged due to addition of the raceway supports. Any penetrations violated for the pulling of cable were resealed per applicable DCPP procedures. There is no impact on the frequency or consequences of any accident or equipment malfunction. The PGA instruments are not part of any TS-required function; there is no impact on any TS safety margin.

23. Reclassify FCV-430, 461, 495, 496 & 601 to Allow Crediting Remote Operation
DCP J-049259, Rev. 0 (Unit 1) (LBIE Log No. 97-116)
DCP J-050259, Rev. 0 (Unit 2) (LBIE Log No.97-117)

This DCP upgrades the motor control loops for the subject valves from Design Class II to Design Class ID by recognizing that they were originally procured, installed, and maintained in accordance with Design Class ID requirements.

Safety Evaluation Summary

The 50.59 evaluation concluded that upgrading the design classification of these motor control loops for these valves does not impact how they will perform their safety function.

24. Addition of “GO” Pushbuttons to SSPS Safeguards Test Cabinets
DCP J-049298, Rev. 0 (Unit 1) (LBIE Log No. 96-021)
DCP J-050298, Rev. 0 (Unit 2) (LBIE Log No. 97-123)

This design change adds two “GO” push buttons to each of the safeguards test cabinets in the solid-state protection system. This allows testing the steam generator main feedwater supply valves FCV-510/1510, 520/1520, 530/1530, and 540/1540. This design change was implemented during the eighth refueling outages for Units 1 and 2.

Safety Evaluation Summary

The new test pushbuttons do not affect protection circuits. The indirect safety function of the pushbuttons only affects the testing should the pushbutton contact fail open. The added pushbuttons are Class I devices and are not

expected to contribute to the evaluated adverse condition. There is no change in the way the steam generator main feedwater supply/bypass valves operate. The change does not degrade or prevent feedwater isolation. Failure of the test pushbuttons does not affect normal or accident operation of the valves.

25. Modify SCMM Annunciator Alarm
DCP J-049302, Rev. 0 (Unit 1) (LBIE Log No. 96-001)

This change interlocks the sub-cooled margin monitor (SCMM) lo-margin alarm with an existing reactor power permissive, P-10, to maintain the alarm during the appropriate low power operation modes. This alleviates the nuisance alarm at normal power operational modes.

Safety Evaluation Summary

This design change adds another function associated with reactor power permissive P-10. This will result in a revision to FSAR Update Table 7.2-2, "Protection System Interlocks." This wiring change does not affect the Emergency Plan, nor does it affect the Security Plan. The design change will not impact the Technical Specifications. The applicable annunciator response procedure will no longer apply during normal plant operation modes above 10 percent reactor power. This design change will not result in a test, experiment, condition or configuration that will affect the operation of the plant.

26. Utilize Gamma-Metrics Post Accident Monitors as Alternate Source Ranges
DCP J-049320, Rev. 0 (Unit 1) (LBIE Log No. 97-033)

This design change added continuous visual indication in the control room for the post accident neutron flux monitors to be used as additional source range channels during Mode 6. The indication is provided by connecting an isolated output of the Gamma-Metrics monitors to the plant process computer. This change was implemented during the Unit 1 eighth refueling outage.

Safety Evaluation Summary

The Gamma-Metrics post-accident neutron monitors provide the same level of quality assurance, redundancy, and necessary display range as the normal source range monitors. Because they do not have alarm and audio circuit capability, one normal source range channel must remain operable. The additional channels are used for indication only during Mode 6. The additional channels provide no control or protective functions. Should either operable channel (i.e., normal source range or the Gamma-Metric channels) fail, the actions specified by Technical Specification 3.9.2 will be taken.

27. Replace Rod Insertion Recorder YR-412 With PPC Recorders
DCP J-049346, Rev. 0 (Unit 1) (LBIE Log No. 97-166)

Replace Class II rod insertion recorder (YR-412) with two new miniature recorders that will be used for a different function. The new miniature recorders (YR-800 and YR-801) will be electrically connected to the plant process computer and used as required by the operators. The new recorders will be installed at the same location as the old recorder on Control Console CC1. The function of the new recorders is Class II. This DCP will be implemented during the Unit 1 ninth refueling outage.

Safety Evaluation Summary

The associated instrument recorders and electrical components have a non-safety related function (Class II). The recorders are used for monitoring purposes only. They are not required for the safe shutdown of the plant. The new recorders will be mounted on Control Console CC1, which is a safety-related panel. The new recorders will be seismically mounted. These recorders do not have any impact on the rod control function and do not contribute to the effects of any inadvertent control rod bank withdrawal or control rod ejection.

28. Control Room Shift Foreman Workstation Modifications Phase 2
DCP J-049353, Rev. 0 (Unit 1) (LBIE Log No. 97-168)
DCP J-050353, Rev. 0 (Unit 2) (LBIE Log No. 97-169)

This modification installed a permanent workstation for the Shift Foreman in the Unit 1 main control room. The former Unit 1 Shift Foreman's office was modified to provide office space for the Shift Supervisor and the Assistant Shift Foreman. The permanent workstation in the primary control room area provides the Shift Foreman with a clear "command and control" presence in the main control room, with good visual and audible access to control room operators and contact with plant operation.

This modification addressed recent INPO and NRC criticism of the former Shift Foreman/Control Room arrangement. Previously, the on-duty Shift Foreman was located in an office area adjoining the main control room. That location met the requirement for being within the control room isolation boundary (Reference NUREG-0700, Rev. 0, Guideline 6.1.1.6.a), but did not provide the preferred "good visual and voice contact with the primary operational area." The new configuration enhanced the Shift Foreman's ability to oversee plant operations, and to maintain a more formal and professional atmosphere in the control room.

Safety Evaluation Summary

No plant equipment was modified, so that new or different accidents or malfunctions were not introduced, and the frequency of analyzed accidents was

not increased. There was no change to any Technical Specification safety margin. The modifications were performed with the plant at power. Most of the work was away from the control boards and outside the Control Operator area to reduce the possibility of distractions or accidental equipment actuations that could cause an accident or impair the ability of the operator to respond to an accident or event. During the modifications, the Shift Foreman was continuously provided with all information necessary to respond to plant evolutions or events so that the potential consequences were not affected.

Phase 1 of this work (DCP J-49351) temporarily relocated the Shift Foreman to the Shift Control Operator area. Control room drawings were relocated from the existing cabinet in the center aisle to an area behind the vertical boards. Access through the center aisle was restricted. These factors did not limit the ability of control room personnel to respond appropriately. The limited access areas of the control room were accessible as required. Drawing relocation caused no significant personnel response delay.

Phase 2 removed the temporary Shift Foreman workstation and installed the permanent workstation. The modification did not affect any systems, structures, or components that are relied upon to mitigate accidents. Improved physical presence enhanced the ability of the Shift Foreman to exercise command and control. The more formal and professional control room atmosphere strengthened the ability of the control room crew to respond to normal plant evolutions as well as to the potential accidents and events evaluated in the FSAR Update. The new workstation location did not significantly affect control room personnel access.

29. Replace RWST Range Code 6 Rosemount Level Transmitters
DCP J-049363, Rev. 0 (Unit 1) (LBIE Log No. 97-037)

This change will replace the existing 2-LT-920 & 921, Rosemount Model 1153HD6RC transmitters, with Rosemount Model 1153HD5RC transmitters. This change will decrease the instrument and channel uncertainty and increase the minimum indicated refueling water storage tank (RWST) volume at the low level alarm to greater than the 120,650 gallons of RWST volume assumed in Table 6.3-5 of the FSAR Update.

Safety Evaluation Summary

Increased accuracy of the RWST level instruments does not increase the probability of accidents. The Emergency Plan is not affected by the RWST accuracy. The accuracy of the new transmitters exceeds the minimum accuracy required by the Technical Specifications. The Security Plan is unaffected by the accuracy of these transmitters.

30. Safety Parameter Display System (SPDS) Replacement
DCP J-050123, Rev. 0 (Unit 2) (LBIE Log No. 96-035)

This modification removed and replaced the original Technical Support Center, Emergency Operations Facility (EOF) , and the control room emergency response facility data system (ERFDS)/ SPDS hardware supplied by Babcock & Wilcox (B&W) The original ERFDS functions are now divided between two systems:

- A new computer system provided by this design change provides color graphic SPDS displays

- The ERFDS "Data Recording and Recall" functions used for post-trip review are now performed by the Plant Process Computer (PPC)

The ERFDS was replaced to solve the following problems:

Software errors resulting from operational changes or latent software defects in the original B&W design required operators to implement workarounds due to errors in the critical safety function status tree displays. Such workarounds inhibit or adversely affect the operators' ability to respond effectively to an emergency or a plant transient situation. Hardware failures caused by aging and obsolete components occurred with sufficient frequency that system availability was being adversely affected. In many cases direct replacement parts were not available. The original SPDS was implemented in firmware. PG&E did not possess the development tools needed to make changes. Changes could be purchased only from the original vendor at substantial cost and long lead-time. Even minor changes such as scaling limits or engineering units required an expensive firmware replacement.

Safety Evaluation Summary

The SPDS, PPC, and EOF/TSC activities and functions cannot initiate any accidents or cause any equipment malfunctions or failures. Similarly, these activities and functions cannot affect any Technical Specification safety margins.

However, the SPDS provides information to control room, TSC, and EOF personnel to aid in the development of accident evaluations and responses, and in making decisions regarding protection of the health and safety of the public. If the SPDS displays do not accurately reflect the plant configuration, assessment and response functions by operations and management may be delayed or degraded. The replacement ERFDS/SPDS is designed to facilitate maintenance of its displays to maintain fidelity to an evolving plant configuration. Thus, increased consequences due to inaccurate SPDS displays are not a concern.

31. Connect Condenser Delta-P Signals and Main Generator Auxiliary Panel (PGA Panel) Alarms to the Control Room
DCP J-050218, Rev. 0 (Unit 2) (LBIE Log No. 97-136)

The purpose of this design change is twofold: (1) Permanently connect the condenser delta-P (DP) signals to the plant process computer (PPC) via a new remote multiplexer panel, PK011. By having the condenser DP signals in the control room on the PPC, operators can have early warning of an upward trend by using the PPCs variable alarm capability. (2) Connect the main generator auxiliary alarms (panel PGA) to the Control Room via the same remote multiplexer panel, PK011, used in Purpose 1. The existing Rochester alarm system in panel PGA is replaced with a Ronan supplied lampbox (PK21), which is driven by the main annunciator system (MAS) via isolated data links. The purpose is to provide the operators with individual alarms (vs grouped or general alarms) associated with the main generator in order to promote timely response to system troubles. In addition, the 20+ year old Rochester annunciator system is replaced.

Safety Evaluation Summary

The safety evaluation deals mainly with Purpose 2 above. The condenser DP connection to the control room (Purpose 1) did not require a revision to the FSAR Update. The connection of the PGA panel to the MAS required a clarification to the FSAR Update statement that the MAS is seismically qualified. This design change added a paragraph to the FSAR Update to clarify that the main generator alarms connected to the MAS via a remote multiplexer are not seismically qualified; however, these connections are isolated by qualified means. There is no failure mechanism of the data link, remote multiplexer, or remote visual annunciator drivers that can adversely impact the function of the MAS following an earthquake. The main generator alarms provided by the remote multiplexers are Design Class II and are not needed to maintain the plant in a safe shutdown condition or to mitigate the consequences of seismic events.

The existing text was clarified by making two additional minor changes that did not impact the conclusion: (1) The MAS is seismically qualified to remain functional after an earthquake. (2) The alarms associated with the main generator are not seismically qualified, but will not adversely impact the system function following an earthquake. The main generator alarms are not needed to mitigate the consequences of seismic events.

32. Modify SCMM Annunciator Alarm
DCP J-050302, Rev. 0 (Unit 2) (LBIE Log No. 96-002)

This change interlocks the subcooled margin monitor (SCMM) lo-margin alarm with an existing reactor power permissive, P-10, to maintain the alarm during the

appropriate operational modes, low power operations. This alleviates the nuisance alarm at normal power operational modes.

Safety Evaluation Summary

This design change adds another function associated with reactor power permissive P-10. This will result in a revision to the FSAR Update Table 7.2-2, Protection System Interlocks. This wiring change does not affect the Emergency Plan, or the Security Plan. The design change will not impact the Technical Specifications. The applicable annunciator response procedure will no longer apply during normal plant operation modes above 10 percent reactor power. This design change will not result in a test, experiment, condition or configuration that will affect the operation of the plant.

33. Replace RWST Range Code 6 Rosemount Level Transmitters
DCP J-050363, Rev. 0 (Unit 2) (LBIE Log No. 97-036)

This change will replace the existing 2-LT-920 & 921, Rosemount Model 1153HD6RC transmitters, with Rosemount Model 1153HD5RC transmitters. This change will decrease the instrument and channel uncertainty and increase the minimum indicated refueling water storage tank (RWST) volume at the low level alarm to greater than the 120,650 gallons of RWST volume assumed in Table 6.3-5 of the FSAR Update.

Safety Evaluation Summary

Increased accuracy of the RWST level instruments does not increase the probability of accidents. The Emergency Plan is not affected by the RWST accuracy. The accuracy of the new transmitters exceeds the minimum accuracy required by the Technical Specifications. The Security Plan is unaffected by the accuracy of these transmitters.

34. Canopy Seal Clamp Assemblies at Spare CRDM Nozzles
MMP M000036-1, Rev. 1 (Unit 2) (LBIE Log No. 98-028)

This Maintenance Modification Package (MMP) is created to allow for installation of canopy seal clamp assemblies (CSCAs) and dummy can adapters onto canopy seal welds on the reactor vessel closure head CRDM penetrations. The CSCAs are designed to encapsulate defective canopy seal welds, functioning as an additional barrier to prevent migration of reactor coolant from a weld defect onto the carbon steel reactor vessel closure head.

Safety Evaluation Summary

The CSCAs are safety-related components that are designed and fabricated for reactor coolant system pressure, temperature and loading conditions in

accordance with applicable ASME Codes, and interfacing instructions for the CRDM nozzles. Installation of the CSCAs will be in accordance with DCPP's ASME Section XI Program Plan and controlled with approved plant maintenance procedures.

The CSCA serves as a backup device to prevent the leakage of reactor coolant through a defective canopy seal weld from corroding the carbon steel reactor vessel closure head. In this capacity, the CSCA functions to reduce leakage from the defective canopy seal weld and thus prevent the leakage from increasing. Leakage, if present, from the CSCA will be detected by the leakage detection method. Any leakage attributed to the clamp will be classified as "unidentified" to which a 1 gpm limit required by the Technical Specifications will apply. Therefore, there is no reduction in the margin of safety as defined in the basis for any Technical Specification.

35. Steam Generator Mechanical Plugging
MMP M000043-1, Rev. 2 (Units 1 & 2) (LBIE Log No. 98-021)

This change authorizes the mechanical plugging of steam generator tubes that have been identified for removal from service as a result of tube inspections. The repair consists of installing erosion/corrosion resistant mechanical rolled plugs at the steam generator tubesheet.

Safety Evaluation Summary

The integrity of the reactor coolant system (RCS) and of the steam generators is maintained by the installation of these plugs. There is no change in design or functions of the steam generators. The integrity of the plugs is assured by the qualification of the process used to install the plugs and by evaluations to confirm the design will perform the intended function. Similar mechanical plugs are already in service in the steam generators.

The plugs are installed in a way compatible with the overall integrity of the tubesheet. These modifications only affect localized passive structural components. This change does not authorize the removal and plugging of tubes in excess of the present limit of 15 percent of the plugged steam generator tubes. This change does not result in a reduction in the margin of safety as defined in the Technical Specification bases.

36. Installation of Framatome Weld Plugs in Steam Generator Tubes
MMP M000044-1, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-076)

This design change allows installation of Framatome weld plugs in defective steam generator tubes at DCPP Units 1 and 2.

Safety Evaluation Summary

Installation of a welded plug to remove defective tubes from service maintains the integrity of the reactor coolant pressure boundary for all normal and postulated accident conditions. The weld plug material and weld filler material used for installation are compatible with the tube/tubesheet and are not susceptible to degradation that caused the tube to become defective.

37. Steam Generator Tube Pull (FTI)
MMP M000055-1, Rev. 1 (Units 1 & 2) (LBIE Log No. 98-022)

This change authorizes the removal of steam generator (SG) tubes from each of the SGs. The removed SG tubes will provide samples for visual inspection as well as provide samples for laboratory examination and analysis which can aid in better understanding of tube degradation and failure mechanisms. Also, the results will provide a direct correlation between the indications and eddy current test results.

Safety Evaluation Summary

The process employed to remove the tube segments is designed and procedurally controlled to prevent contact with adjacent tubes. Further, the tube remnants remaining in the SG have been analyzed to show that no compromising contacts with adjacent tubes will occur during normal operations and accident conditions. With removal and plugging of some tubes per this MMP, the total number of plugged tubes in the SGs will still be a small fraction of the total tubes.

The removal of flow area by plugging still maintains the circulation capability of the loops well above that required and/or assumed in plant analyses. This change does not compromise the operability of the SGs including the flow and heat transfer capability and pressure boundary integrity during normal operation and postulated accidents. Therefore, this change does not result in a reduction in the margin of safety as defined in the Technical Specification bases.

38. Installation of Framatome U-Bend Stabilizer in Steam Generator Tubes
MMP M000057-1, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-090)

This design change allows installation of Framatome U-bend stabilizers in defective steam generator (SG) tubes requiring stabilization.

Safety Evaluation Summary

Installation of Framatome U-bend stabilizers in defective SG tubes, in conjunction with tube plugging, maintains adjacent SG tube structural and leakage integrity by preventing damage to adjacent tubes during normal and

accident flow induced vibration loading. Stabilization prevents the possibility of a tube section becoming a loose part in the secondary system. The integrity of the tube plugs is maintained. The stabilizer material is not susceptible to degradation.

39. Determinate Defective Pressurizer Heaters
MMP M000058, Rev. 2 (Unit 1) (LBIE Log No. 97-197)
MMP M000058, Rev. 1 (Unit 1) (LBIE Log No. 97-027)
MMP M000059, Rev. 2 (Unit 2) (LBIE Log No. 97-198)

This Maintenance Modification Package (MMP) allows pressurizer heaters that have failed to be disconnected. This allows other heaters that are fed from the same circuit breaker to be returned to service. The initial pressurizer heater capacity was 1800 kW. This MMP allows failed heaters to be disconnected as long as the connected capacity is at least 1340 kW with Heater Groups 1 and 4 each having at least 276 kW connected and Groups 3 and 4 each having at least 345 kW connected.

Safety Evaluation Summary

The pressurizer heaters are nonsafety-related. The purpose of the pressurizer heaters is to control pressurizer pressure during heat up and power operation and to support natural circulation of the reactor coolant system during the loss of offsite power. 150 kW is required to support natural circulation. Technical Specifications define the minimum pressurizer heater capacity as 150 kW from two groups which can be supplied by vital emergency power. This MMP maintains this 150 kW by limiting the number of heaters that can be disconnected. Therefore, all margins of safety implicit in this Technical Specification requirement are maintained by this MMP.

40. Replace 4-kv Potential Transformer Primary Fuse
MMP M000066-1, Rev. 1 (Unit 2) (LBIE Log No. 98-012)

Licensee Event Report (LER) 1-97-010-01, “Unplanned Start of Diesel Generator 1-1 Due to a 4160-V Bus H Startup Feeder Phase Potential Transformer Opened Fuse,” discusses the event, root cause and possible upgrade of the primary fuse from 1/2 ampere to 1 ampere. Maintenance Modification Package M000066, Rev.1, allows the replacement of Units 1 and 2, 4 kV vital and nonvital potential transformer primary fuses. The replacement fuses have a 1 ampere current rating in place of the existing 1/2 ampere rating. While the 1/2 ampere rating is acceptable, the 1 ampere rating increases the inrush current margin to allow more reliable operation. The replacement fuses have the same physical characteristics as the existing fuses.

Safety Evaluation Summary

The plant configuration and operational logic remains unchanged.
The failure analysis concluded that the most likely cause of failure was accumulated fuse element degradation due to current surges on the fuse over the life of the plant. Increasing the replacement fuse inrush capability implements the analysis recommendation. The safety function of the 4-kV potential transformer is to provide a signal, for control and instrumentation, which is proportional to the voltage of the bus or feeder. The safety function of the primary fuse is to carry load/inrush current and provide short circuit protection to the potential transformer.

The replacement fuse maintains coordination with existing fuses and relays, is safety related, and meets the requirements of PG&E Design Class I and IEEE 308 Class IE. Since the 1 ampere replacement fuse has three times the inrush capability of the 1/2 ampere existing fuse, the probability of occurrence of a fuse blow malfunction during operational transients is decreased, and the availability of potential transformers to perform safety related instrumentation and control functions is increased. The 4-kV primary fuse has no effect on any radiation barrier or offsite dose..

41. Replacement of Diesel Fuel Oil Tank 0-1
DCP M-049160, Rev. 0 (Units 1 & 2) (LBIE Log No. 96-004)

This modification consists of replacing the 40,000 gal. single-walled diesel generator fuel oil tank 0-1 and associated piping up to the pump vaults with a new 50,000 gal. double walled tank and new piping. The design change package also installed a leak detection system for the tank and piping. The overall function of the tank and piping remained the same. The purpose for the replacement was to meet the new California Code of Regulations.

Safety Evaluation Summary

The removal of one of the two diesel fuel oil storage tanks from service has been reviewed by the NRC. To permit replacement of the tanks, the NRC has issued License Amendments 108 and 109 to permit operation of the plant for up to 120 days with a single operable diesel fuel oil tank. The fuel supply to each of the diesel generators is being preserved for the duration of the construction activities required to implement the design change. Construction procedures and work plans assure that the function of the 0-2 diesel fuel oil supply system and the capability of performing that function are not altered during the diesel fuel oil tank 0-1 replacement activities. The final configuration of the diesel fuel oil system following the implementation of the design change assures that the system design, function, and method of performing its function are unchanged or enhanced.

42. Requalification of the CCWS for a Maximum CCW Post-Accident Supply Temperature of 140°F
DCP M-049291, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-158)
DCP M-049291, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-077)

This design change package (DCP) established a new postaccident temperature limit profile for the component cooling water system (CCWS). This was achieved by upgrading individual components' temperature qualifications where necessary and revising the associated design and licensing documentation. This DCP was performed to document previously unrecognized margin between the postaccident CCW supply temperature profile and the documented CCWS equipment temperature limitations.

Safety Evaluation Summary

The bases for the 50.59 conclusions are (1) that raising the qualified post-accident system temperature limit does not effect how the system will actually respond to an accident, and (2) the new elevated temperature limits do not affect the capability any CCW (or related system) equipment to perform its safety function.

43. Removal of Halon from SSPS Rooms
DCP M-049295, Rev. 0 (Unit 1) (LBIE Log No. 96-010)
DCP M-050925 Rev. 0 (Unit 2) (LBIE Log No. 96-011)

These design changes removed the Halon fire suppression system from the Unit 1 and Unit 2 solid-state protection system (SSPS) rooms. It was difficult to maintain the leak-tightness of the ceiling of these rooms as required to maintain the Halon concentration in the event of a fire. In addition, the release of Halon to the atmosphere has adverse environmental consequences, and it is no longer commercially available. Since the system is not required to satisfy Appendix R safe shutdown requirements, it was not replaced with an alternative fire suppression system. However, the existing fire detection system and alarms were left in place.

Safety Evaluation Summary

The absence of the Halon system has no effect on the probability of a fire occurring in the SSPS rooms. The removal of the system does not increase the analyzed consequences of a fire in the SSPS rooms because the current analysis assumes the loss of an SSPS train as a result of a fire. Removal of the Halon suppression system does not impact the ability to achieve and maintain safe shutdown of the plant; once the reactor is tripped, the equipment in the SSPS room is no longer required to maintain safe shutdown. Manual actions and redundant safe shutdown components, not the Halon system, are credited for mitigating the effects of a fire in this area. The operation of the SSPS

computers will not be affected by the change, and the consequences of a fire in this area are unchanged from those already evaluated.

44. CCP 1-1 and 1-2 Gear Oil Cooler Replacement
DCP M-049312, Rev. 0 (Unit 1) (LBIE Log No. 96-014)
DCP M-050312, Rev. 0 (Unit 2) (LBIE Log No. 96-015)

This design change installed new centrifugal charging pump (CCP) gear oil coolers on the 1-1 and 1-2 CCPs to enhance heat transfer and raise temperature qualification.

Safety Evaluation Summary

This 50.59 evaluation concludes that there is no unreviewed safety question concerning replacement of the coolers. This conclusion is reached because (1) the coolers transfer as much (or more) heat from the CCP gear oil, enhancing the CCP's ability to perform its design function, and (2) the coolers are installed in the same configuration and to the same design qualification as the previous coolers.

45. CCW-1-TCV-130 Replacement (HOT TAP)
DCP M049319 (Units 1 & 2) (LBIE Log No. 97-089)

See LBIE 97-046 (Procedure MP I-38-M.1, Units 1 & 2, Rev.0 in "Procedures" section of report). This was a revision to LBIE Log No. 97-046 that changed the mode that work could be conducted. The mode was change from 0 to Modes 5, 6, or 0.

Safety Evaluation Summary

This change only applies to Mode 6 with fuel removed from the reactor vessel. Therefore, because the reactor coolant system is still depressurized, there is no possibility the change involves an unreviewed safety question (see LBIE Log No. 97-046).

46. Revise Design Basis for ASW Pump Motors
DCP M-049385, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-137)

In 1988, the auxiliary saltwater (ASW) pump impellers were replaced with those of larger diameter under Design Change Package (DCP) M-39834. The increase in impeller size has caused the pump motor to operate beyond its nameplate rating (400 hp). This condition (450 hp) of operation was evaluated by plant engineering and accepted. Based on a subsequent engineering Calculation M-854 and its supporting test data, the power supplied by the motor, while operating in a single pump/two heat exchanger configuration, can be as high as 465 hp (conservatism included).

PG&E electrical engineering and Westinghouse (the motor manufacturer) has evaluated that the motors are capable of operating at 465 hp without exceeding their design limits. This evaluation was documented in two engineering memos and a Westinghouse letter. DCP M-049385 is used to accept the extended rating (465 hp) as the new limit for the ASW pump motor operation and to revise the Design Criteria Memorandum S-17B, as well as the FSAR Update sections.

Safety Evaluation Summary

There are no known impacts on the equipment important to safety for accident events due to the ASW pump motor operating in a higher rating up to 465 hp. The increase in ASW pump motor hp can cause a higher consumption in diesel fuel and can affect the adequacy of diesel fuel inventory. Such impacts have been evaluated in engineering Calculation M-786, Rev. 8, and the new hp rating (465 hp) has been used to establish the minimum required fuel storage to meet the license bases.

The increase in ASW pump motor hp may affect diesel loading and loading sequence, motor protective relay setpoints, feeder cable ampacity and voltage drop, and the motor stator temperature rise. These issues have been addressed by electrical engineering and Westinghouse (the motor manufacturer) and concluded that the ASW motors are capable of operating at 465 hp without exceeding the design limits for the motors and the diesel generators. This evaluation was documented in engineering memos. The increase in ASW pump motor hp will affect the internal thermal load for the pump vaults. This increase has been analyzed by engineering and documented in HVAC Calculation 82-6, Rev. 5. Therefore, the probability of a malfunction of equipment important to safety previously evaluated in the FSAR Update will not be increased.

47. Revised Peak CCW Temperature Following a Design Basis Accident
DCP M-049386, (Units 1 & 2) (LBIE Log No. 98-070)

The limiting component cooling water (CCW) temperature transients following a design basis accident (DBA) have been reevaluated by Westinghouse in WCAP-14282, Revision 1, dated December 1997. Revised WCAP-14282 captures previous CCW heatup evaluations contained in several documents and incorporates the latest design input while using the same methodology used in past analyses.

Safety Evaluation Summary

The evaluation specifically addressed the following topics: (1) incorporation of WCAP-14282, Rev. 1, into the licensing and design bases, (2) establishment of an elevated ultimate heat sink temperature limit of 70°F, (3) revision of the normal maximum operating CCW temperature from 120°F to 80°F for Modes 1-3

and 95°F for Modes 4-5, (4) a revised bases for operation of two RHR trains of CCW/ASW in the cold leg recirculation phase, (5) a revised bases for the CCW heat exchanger saltwater inlet valve (1/2-FCV-602 and -603) required 8-hour hold time, and (6) clarification that during post-LOCA split-train operation, operator action is required to recover from specific active failure scenarios. None of these topics involve physical changes to the plant. The evaluation concluded that the proposed changes do not involve an unreviewed safety question.

48. EDG Rooms - CO_2 Manual Actuation Switches: Relocation
DCP M-050366, Rev. 0 (Unit 2) (LBIE Log No. 97-186)

The emergency diesel generator CO_2 manual actuation switches were moved from the south wall of the turbine building to a location outside the diesel generator rooms in the corridor. The relocation was required because the switches were originally located in Pyrocrete boxes that did not conform to a tested configuration. Offsite power circuits were located in vicinity of the switches. A fire in the turbine building had the potential to disable the diesel generators and damage the offsite power circuits.

Safety Evaluation Summary

This 10 CFR 50.59 safety evaluation was performed because FSAR Update Chapter 9, Appendix 9.5A, specifically stated that the switches are located in Fire Zone 19-A, and are enclosed in Pyrocrete to prevent hot shorts. The switch relocation affected the description of Fire Zone 19-A. Ability to achieve and maintain safe shutdown depends on availability of power to the equipment required for safe shutdown. Relocating the CO_2 manual actuation switches provides increased protection because the switches are now separated from a fire in the turbine building by 2-hour fire barriers. The CO_2 manual actuation switches are not associated with initiation of any accident. The increased separation from potential turbine building fires enhances the ability to protect the diesel generators and reduces the potential for hot shorts to impair operation of the diesel generators. Probability and consequences of accidents or equipment malfunctions are not increased.

49. Convert CCP 1-1 to 3rd Generation Seal Configuration
DCP N-049231, Rev. 0 (Unit 1) (LBIE Log No. 96-016)

The DCP changed/replaced the pump case and internal assembly for Centrifugal Charging Pump (CCP) 1-1 with a like-for-like pump case and internal assembly that has been equipped with the 3rd generation seal configuration. The old seal design (first generation) was a multicomponent assembly requiring external cooling by CCW. Although no known problem is associated with maintenance at DCPP for the 1st generation seals, the conversion to 3rd generation was done as an enhancement, which could increase pump availability.

Safety Evaluation Summary

The replacement of CCP 1-1 with the pump casing and internal assembly from CCP 2-1 is considered a like-for-like replacement. The capability of the CVCS system to meet the functional requirements of the accident analysis is unaffected by this change.

The new 3rd generation mechanical seals meet or exceed the original mechanical seal requirements, with the exception that external cooling is not required. Seal life is extended as a result of the one piece seal sleeve/ pumping ring design. Therefore, the availability of the CCP is increased. Also, because CCW is no longer required for cooling, one of the failure modes that can cause unavailability of the CCP is eliminated.

50. Installation of FE-999
DCP N-049364, Rev. 0 (Unit 1) (LBIE Log No. 97-031)
DCP N-050364, Rev. 0 (Unit 2) (LBIE Log No. 97-032)

This DCP installs a new flow element, FE-999, in the charging injection flowpath downstream of existing FE-917. This was done because of the non-ASME standard installation of FE-917 which is documented in AR A0414083. The effect of this nonstandard installation is such that the bias corrections that would be necessary to correct the reading from FE-917 would restrict the allowable range of settings during the ECCS flow balancing of STP V-15.

Safety Evaluation Summary

While the new flow element will provide a minor restriction to the flow in the charging injection header, it is not the most limiting restriction in the line. Adequate flow is verified by testing each outage by STP V-15.

NDE inspections were performed for the welds on the piping and fittings to assure installation in compliance with applicable construction codes. Testing is performed each outage for injection flow balancing and post loss-of-coolant accident recirculation leakage. All applicable design and licensing standards for the piping and components were complied with to assure all requirements were met in the installation.

Therefore, the installation of this additional flow orifice did not affect the probability or consequences of any accident, new or previously reviewed, nor did it affect the basis for any Technical Specification. There is no affect on the licensing basis of the plant.

51. Gross Failed Fuel Detector Removal (Note: This design change has not been implemented)
DCP N-049369, Rev. 0 (Unit 1) (LBIE Log No. 97-167)
DCP N-050369, Rev. 0 (Unit 2) (LBIE Log No. 97-203)

This design change deletes the gross failed fuel detector (GFFD) system from the NSSS system. The GFFD process skid, and GFFD control console instrumentation will be physically removed. In addition, component cooling water piping, sample tubing, and associated supports will be modified accordingly. This design also includes electrical changes to the GFFD control console and skid power supply and signal wiring. The GFFD control console will remain in-place as it houses main steam line radiation monitors and loose parts monitor pinger circuits.

Safety Evaluation Summary

The GFFD system is not related to any accident previously evaluated in the FSAR Update. The GFFD is a nonsafety-related device, originally designed to monitor reactor coolant during normal operation (for purposes of detecting potential fuel defects). The GFFD provides no accident monitoring function and removal of the GFFD will not affect the capability to obtain a post-accident reactor coolant sample. Process line changes resulting from the GFFD removal are designed to assure leak-tight integrity of the sampling system tubing, and the tubing will continue to be seismically supported to meet system post-HOSGRI cold shutdown requirements. The supply/return piping to the GFFD sample cooler has been redesigned to ensure CCW header “C” efficiencies are not adversely impacted, and the associated piping will continue to be seismically supported. Design changes to the GFFD control console have been seismically qualified to maintain integrity of the main steam line radiation monitors (which are housed within the GFFD control console) and adjacent inter-linked cabinets.

There is no Technical Specification (TS) requirement to provide for continuous on-line sampling of reactor coolant for purposes of assessing core conditions during normal power operation. Currently, reactor coolant sampling is performed on a batch basis, thus meeting the sampling frequency requirements of TS 3.4.8 (RCS specific activity). Frequent TS-required grab sampling will continue to be performed for failed fuel detection. Note that DCPP continues to search for an instrument to detect for severe failed fuel failures in accordance with Safety Evaluation Report Supplement 6. Therefore, elimination of the GFFD system, considering the existing sampling program, will not result in any margin of safety reduction.

52. Install Zinc Injection Subsystem
DCP N-049408, Rev. 1 (Units 1 & 2) (LBIE Log No. 98-069)
DCP N-049408 (Units 1 & 2) (LBIE Log No. 98-025)

Install a skid-mounted, zinc acetate injection subsystem designed to inject zinc into the reactor coolant system (RCS) to inhibit stress corrosion cracking in the Alloy 600 steam generator tubes.

Safety Evaluation Summary

This design change installs equipment to inject zinc into the RCS. The new equipment has no impact on any FSAR Update accidents. With regard to boron dilution, the limited capacity of the zinc injection pumps (less than 2 gallons per hour) is insignificant when compared with the 262 gpm dilution flow considered in the uncontrolled boron dilution accident at power. The zinc injection equipment will not interact with or impact the operation of any equipment important to safety. Therefore, it is concluded that no unreviewed safety question is involved.

53. Design Criteria for CVCS Evaporator Feed Demineralizers Resin Loading
DCP N-049429, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-045)

This design change revises the design criteria for the chemical and volume control system (CVCS) evaporator feed demineralizers to allow variation of the combination of anion and cation resin used in the demineralizers to optimize operation.

Safety Evaluation Summary

The proposed changes in resin loading have no effect on accidents analyzed in the FSAR Update and do not impact operation of equipment important to safety. Therefore, it is concluded that no unreviewed safety question is involved.

54. ECCS Pressure Reducing Orifice
DCP N-050286, (Unit 2) (LBIE Log No. 98-006)
DCP N-050286, Rev. 0 (Unit 2) (LBIE Log No. 97-152)

This DCP modified both the charging and safety injection lines of the emergency core cooling system (ECCS). A pressure reducing orifice assembly and trimming orifice were installed in each charging injection line. The charging injection throttle valves 8810A-D, flow orifices (FE 924-927), interconnecting piping, and orifice flanges were replaced. In each safety injection cold leg, a pressure reducing orifice assembly was installed and the flow orifices (FE 974-977) were replaced.

Safety Evaluation Summary

The addition of pressure reducing orifice assemblies and trimming orifices coupled with the replacement of the charging throttle valves, flow elements, and orifice flanges is to prevent pump runout of centrifugal charging pumps (CCPs) and safety injection pumps (SIPs), as well as to avoid potential ECCS flow

blockage during the sump recirculation phases. The ECCS delivers flow to the reactor vessel for core cooling and to provide additional shutdown capability following an accident. The ECCS performance is evaluated by using the minimum and maximum pump curves coupled with the maximum and minimum system resistances, which results in the minimum and maximum ECCS injection profiles. System resistance provided by the ECCS throttle valves in each injection line minimizes the spill flow through the broken line and prevents pump runout during a postulated LOCA. The addition of passive pressure reducing orifice assemblies and passive trimming orifices results in distribution of the system resistance previously provided by the single throttle valve. The replacement of charging injection throttle valves and flow elements provides an enhanced design of the existing components.

Since ECCS is not considered an accident initiator and the addition of the passive components does not create new failure modes, this modification does not impact the possibility of an accident nor the consequence of an accident as previously evaluated in the FSAR Update. The addition of the passive components to share the system resistance does not reduce the margin of safety as defined in the basis for any Technical Specification.

55. <u>21-Month Cycle, Unit 2 Cycle 8</u>
DCP N-050382, Rev. 0 (Unit 2) (LBIE Log No. 97-163)

This design change authorized the extension of Unit 2 Cycle 8 from 18 months nominal to 21 months nominal.

Safety Evaluation Summary

The LBIE for this design change reviewed the following items:

- The use of 1.25 grace period for the not yet surveillance test procedures affected by the approved License Amendment Requests 95-07, 96-10, 97-01, and 97-07
- Changes to instrument setpoint and postaccident monitoring calculations
- Design change notice for changing the pressurizer level high trip setpoint
- Evaluation of steam generator tube integrity
- Impact on major plant systems and components
- Changes to DCMs and FSAR Update
- Effect on Emergency Plan

Based on this review, there were no 10 CFR 50.59 safety issues or unreviewed safety questions identified.

56. Replace Containment Recirculation Sump Screen
DCP N-049317, Rev. 1 (Unit 1) (LBIE Log No. 97-084)

This DCP modifies the Unit 1 outer containment recirculation sump screen (top, sides, and front inclined sections) by replacing the existing mesh with a 1/8-in. mesh opening. This modification is necessary because DCPP has the potential to pass debris through the sump screen that could potentially block flow through the safety injection to cold leg and charging injection to cold leg throttle/runout valves during the recirculation phase of a loss-of-coolant accident (LOCA).

Safety Evaluation Summary

Rescreening with a smaller mesh size will improve the sump's capability to filter out debris, and when combined with another modification to increase the minimum opening in the ECCS injection lines, the possibility of ECCS flow blockage will be minimized. The sump's function of providing a source of long-term cooling water following a LOCA is not compromised for the following reasons: the sump's structural and seismic integrity is maintained, the required free flow area is maintained under minimum LOCA water level and debris blockage conditions, adequate RHR pump NPSH is maintained, vortex suppression is maintained, no new seismically induced system interaction or high energy line break concerns are created, material selection maintains

structural/ functional integrity under all conditions, and the new design does not interfere with the sump level instrumentation.

57. Unit 1 Cycle 9 Reactor Core Reload
DCP N-49368, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-081)

This design change authorized the reloading of the Unit 1 core in a specific pattern of new and partially spent fuel, which is known as the Cycle 9 reload core.

Safety Evaluation Summary

The LBIE for this design change relies, in part, on information provided by the Westinghouse Reload Safety Evaluation that is specific for the core design of Unit 1 Cycle 9. There is no change from previous core designs that triggered the need for prior licensing review. Based on a review of the FSAR Update and associated Chapter 15 accident analysis, there were no 10 CFR 50.59 safety issues or unreviewed safety questions identified.

58. Unit 2 Cycle 9 Reactor Core Fuel Load
DCP N-050368, Rev. 0 (Unit 2) (LBIE Log No. 98-024)

This design change incorporates the new core design from Westinghouse for operation of Unit 2 Cycle 9. This is done routinely for each reload cycle since cores eventually become less reactive and need the addition of new fuel to start a new cycle.

Safety Evaluation Summary

The fabricator provided a 10 CFR 50.59 safety evaluation that verified there are no impacts to the reference safety analyses in the FSAR Update, no unreviewed safety questions, and no impacts on the plant Technical Specifications. This core design meets all the design criteria for maintaining its design basis function. The features implemented in this design are similar to those implemented in previous cores.

59. Unit 2 Overpressurization Protection of Penetrations 49 and 50
DCP P-050371, Rev. 0 (Unit 2) (LBIE Log No. 97-156)

This plant modification added holes to the upstream side of the inner containment isolation ball valves in the liquid radwaste system on containment penetrations 49 and 50. This change protects the integrity of the isolated penetrations against failure in the event a design basis accident were to cause heating, expansion, and pressurization of the fluid trapped between the isolation valves. The change also provides a rupture disc upstream of the valve on penetration 50 to ensure a lower pressure relief path is available during a design

basis accident. This change is in response to evaluation of the concerns of Generic Letter (GL) 96-06.

Safety Evaluation Summary

The change is necessary and capable of ensuring the containment isolation system will meet its design and license basis requirements in the event of a design basis accident as detailed by GL 96-06. That is, the change must be implemented to ensure the penetration is not overpressurized due to expansion of the trapped fluid during a design basis accident.

No new containment isolation failure modes were introduced by the change and the designed failure of the rupture disc in the event of a design basis accident will not affect the consequences of the event. Further, the design and procurement quality of the rupture disc ensure that its failure and the subsequent radwaste spill inside containment would not occur for the range of radwaste system operating conditions.

60. Manipulator Crane Parking Position Limitation
DCM S-42B (Units 1 & 2) (LBIE Log No. 97-054)

This evaluation considers the movement of the manipulator crane from its eastmost position over the refueling cavity during operating Modes 1 through 5. Hosgri correspondence to the NRC stated that the crane would be “parked at east end of its travel during this mode (power operation to cold shutdown).” The Hosgri Report states that the crane will not be used in Modes 1 through 5. The capability to move the crane during these modes is necessary to facilitate preventative maintenance and testing of the crane itself or to allow access to structures, systems, or components adjacent to but blocked by the crane (e.g., hatches, lower cavity area, fuel transfer system upender, and cart winches).

Safety Evaluation Summary

The manipulator crane and its support rails remain qualified for Hosgri independent of the parked position of the crane. Civil Engineering has evaluated the crane and containment for seismic and seismically induced system interaction (SISI) effects and have concluded that the configuration is acceptable provided the crane is not parked closer than 5 feet to structures, systems, and components in its travel path. The SISI spacing criterion described above would assure that the manipulator crane would not strike these components, thereby precluding secondary interactions.

61. Avoidance of Unnecessary Thermal Transients on Alternate Charging Nozzle
DCM S-8, Rev. 6 (Units 1 & 2) (LBIE Log No. 97-128)

This change adds a new entry in the Precautions and Limitations section of the chemical and volume control system design basis document to reflect the Westinghouse recommendation that use of alternate charging be minimized during normal power operation to avoid unnecessary thermal transients on the alternate charging nozzle, and to state that, on this basis, the Inservice Test Program stroke testing of normal charging line Valves 8146 and 8147 should be performed on a cold shutdown frequency rather than quarterly. Excessive use of alternate charging could contribute to eventual fatigue failure of the alternate charging nozzle, resulting in a loss-of-coolant accident.

Safety Evaluation Summary

The normal charging flow path on which these air-operated, fail-open valves are located is isolated by a safety injection signal, so the postaccident position of these valves is inconsequential for purposes of accident mitigation. Hence, the stroke times of these valves has no effect on the consequences of an accident.

B. Temporary Modifications, Electrical Jumpers and Lifted Leads, Mechanical Jumpers and Bypasses, and Test Equipment

1. Jumper to Provide Non-1E Power to ABVS Supply Fan, S-32,Rev. 0, Rev. 1, and Rev. 2
(Unit 1) (LBIE Log No. 97-094)

This LBIE evaluates the activity of installing a jumper to allow the operation of the auxiliary building ventilation system (ABVS) Supply Fan S-32 from a nonvital electrical bus during the Unit 1 eighth refueling outage. Fan S-32 provides ventilation cooling air to rooms housing emergency core cooling system (ECCS) components in the auxiliary building. Normally, Fan S-32 is powered by vital Bus H, which would not be available. The redundant supply Fan S-31 was also not available due to the outage of Bus F. This jumper was applicable during Modes 5 and 6. Technical Specification 3/4.7.6 requires the ABVS to be operable in Modes 1 through 4 to ensure that radioactive materials leaking from the ECCS equipment within the auxiliary building following a LOCA are filtered prior to reaching the environment . The ABVS also has the support function to provide ventilation cooling to the areas containing safety-related equipment that is required to be operable to mitigate the consequences of certain design bases accidents and to provide safe shutdown . During defueled condition, Mode 6 or Mode 5, the ABVS has a support function to provide cooling air to the engineered safety features (ESF) equipment rooms served by the ABVS. The installed jumper would allow the ABVS to provide sufficient cooling to the ESF equipment rooms as required during the applicable modes. This jumper was issued as Rev. 0, Rev. 1, and Rev. 2. Only Rev. 2 was installed.

Safety Evaluation Summary

The jumper allowed the ABVS to perform its support function of providing ventilation cooling function to the ESF equipment. The jumper was adequately sized for the expected fan motor loads. In this configuration, Supply Fan S-32 would supply the design bases air flow required to maintain the ESF equipment at their normal operation temperature. The ambient room temperature of the ESF pump rooms (SI, CCW, RHR, charging, and containment spray) in the auxiliary building are monitored. If failure of the non-vital power supply occurred, the pumps would remain operable until the temperature increased to 30°F above the limits stated in Equipment Control Guideline (ECG) 23.1 (133°F for charging and RHR, 141°F for CCW). If the room temperatures reached these limits, corrective actions to provide adequate cooling would be taken to restore room temperature to within limits within the allotted 4-hour limiting condition for operation (LCO). The actions would consist of opening doors or installing a readily available gas-powered temporary power supply and portable fans to direct cooling air to the affected areas. Exceeding the monitored temperature limits does not mean that the equipment will fail, but only that an analysis would be required to evaluate the impact of the higher temperature had on the

operating life of the equipment. Thus, this jumper will not cause the malfunction of equipment important to safety.

2. TSR-98-036 Lead Shielding Request per Procedure RP1.ID2
(Unit 2) (LBIE Log No. 98-015)

This temporayr modification allowed installation and removal of temporary lead shielding on Unit 2 Lines 508, 509, and 927, located above the residual heat removal (RHR) sump in containment. The shielding will be installed in Modes 5 and 6 only and removed prior to entering Mode 4. The shielding will be installed on operable piping which creates a condition that might affect safe operation of the plant not evaluated in the FSAR Update.

Safety Evaluation Summary

The only Mode 5 and 6 accident analyzed in the FSAR Update is a fuel handling accident. The addition of lead shielding onto an operating residual heat removal line does not affect this accident. The blankets' tie-down arrangement is considered structurally adequate such that it will not fail during a seismic event and damage any seismically induced systems interaction targets in the vicinity. Additional weight of the blankets has been evaluated for its impact on the seismic qualifications of piping and found to be acceptable. Based on the above criteria and justification, an unreviewed safety question is not involved.

3. EDG 1-2 Lube Oil Heater-Jumper No. 1-97-012 Alternate Power Supply During 1R8-Bus F Clearance
Jumper 1-97-012, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-048)
Jumper 1-97-013, Rev. 0 (Units 1 & 2) - Bus G (LBIE Log No. 97-047)
Jumper 1-97-015, Rev. 0 (Units 1 & 2) - Bus H (LBIE Log No. 97-049)

This jumper permits emergency diesel generator (EDG) 1-3 lube oil heater to be energized from another power source during the Unit 1 eighth refueling outage for the Bus H clearance.

Safety Evaluation Summary

The Technical Specifications require one operable diesel generator in Modes 5 and 6. With the installation of this jumper, EDG 1-2 will remain operable. Energizing the lube oil heater from another source will have no impact on the accidents evaluated in the FSAR Update. In case of an electrical fault associated with the jumper, the supply breakers will clear the fault. The loss of power to the auxiliary panel has no impact on the EDG to start and load. This jumper is installed to maintain lube oil temperature above 90°F and will prevent unnecessary EDG starts to heat up the lube oil. This will permit EDG 1--2 to remain operable and one more EDG will be either operable or available. Based

on the above, this jumper will not reduce the margin of safety as defined in the basis for the Technical Specifications.

4. Control Room Ventilation System Troubleshooting
Jumper 97-007, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-051)

This LBIE associated with Jumper 97-007 assisted with the troubleshooting efforts associated with AR A0427712 that effected the control room ventilation system (CRVS) and the pressurizer acoustic monitors. In order to successfully troubleshoot and repair the circuit, a jumper was needed to lift certain circuits while maintaining the operability of the CRVS.

Safety Evaluation Summary

The evaluation screen for this condition screened "Yes" as a change to the system operation as described in the FSAR Update. The safety evaluation determined that an unreviewed safety question is not involved based on the Technical Specifications (TS) allowing the plant to operate with only one train of CRVS. Since the jumper would only effect one train, the other train would always be available to satisfy the operability requirements. The plant would enter the TS limiting condition for operation for one train inoperable during the evolution.

5. Add Local Manual Control of CND -2-TCV-23
Jumper 97-018 (Units 1 & 2) (LBIE Log No. 97-120)

A temporary local manual control setup was installed to bypass the normal automatic controls of Valve CND-2-TCV-23. This enabled TCV-23 to remain in service during the replacement of a faulty control element while the plant was on line. TCV-23 cannot be removed from service while the plant is operating.

Safety Evaluation Summary

TCV-23 is Class II (nonsafety-related) and is not included in any Technical Specifications. This jumper disabled TCV-23 to respond to a load transient bypass signal (LTBS) as described in the FSAR Update. Plant generation was reduced to below the 69 percent power level during the installation of the jumper and replacement of the control element. The LTBS cannot be initiated below this power level.

6. STSR-97-137 Lead Shielding Request per Procedure RP1.ID2
STSR 97-137, Rev. 0 (Unit 1) (LBIE Log No. 97-060)

This temporary modification allowed installation and removal of temporary lead shielding in Unit 1 containment for Line 256, Rupture Restraints 4-1RR and 4-2RR. The shielding will be installed in Modes 5 and 6 only and removed prior

to entering Mode 4. The shielding will be installed on operable piping which creates a condition that might affect safe operation of the plant not evaluated in the FSAR Update.

Safety Evaluation Summary

The only Mode 5 and 6 accident analyzed in the FSAR Update is a fuel handling accident. The addition of lead shielding onto an operating residual heat removal line does not affect this accident. The blankets' tie-down arrangement is considered structurally adequate such that it will not fail during a seismic event and damage any seismically induced systems interaction targets in the vicinity. Additional weight of the blankets has been evaluated for its impact on the seismic qualifications of piping and found to be acceptable. Based on the above criteria and justification, an unreviewed safety question is not involved.

7. Temporary Modification to the VLPM
Jumper 98-001, Rev. 5A (Unit 1) (LBIE Log No. 98-011)

The vibration and loose parts monitor (VLPM) Channel 6 input lead is lifted by this jumper to prevent nuisance alarms that have been occurring since the Unit 1 eighth refueling outage. The field lead from Channel 6 into the VLPM has a single BNC connector at the end that is disconnected until the source of the noise on the field lead can be determined during the next outage. The implementation of the configuration change reduces the number of inputs as shown in the design documents, and therefore, the design redundancy of the signal from Steam Generator 1-1 loose part monitoring no longer exists. This design redundancy is stipulated in the FSAR Update (Section 4.4.5.4) and, though this limit is descriptive of the system, any change in that description constitutes a change in the FSAR Update text and/or tables. Thus, Question 1a) of the LBIE screen is answered "Yes." Section 4.4.5.4 of the FSAR Update further describes what occurs when the output of an individual transducer channel exceeds an adjustable setpoint. This description includes operator actions and staff actions that qualifies as a procedure as described in the FSAR Update.

Safety Evaluation Summary

The VLPM provides early detection of potential loose parts in the reactor coolant system (RCS) so remedial action may be taken before damage occurs. With one SG 1-1 VLPM channel disabled, one channel remains. The loose parts monitoring computer software has been adjusted to provide an alarm on the one remaining input. The resulting loose parts alert capability is more conservative in this configuration because both channels must read high to initiate an alarm with two channels available. The probability of an accident or equipment malfunction caused by the lifted input lead will not contribute to an increased accident or

equipment malfunction frequency because SG 1-1 loose parts monitoring capability is maintained more conservatively than described in the FSAR Update.

The VLPM is a Class II monitoring system that is not required to mitigate the consequences of any FSAR Update accident or equipment malfunction. This jumper does not raise the consequences of any evaluated accidents or equipment malfunctions in which loose parts are monitored whether the loose parts contribute to the accident or not.

VLPM operability is controlled by ECG 46.1. VLPM function is maintained. No margins of safety for this system are described in the ECG bases or the FSAR Update.

8. Temporary Jumper for Lube Oil Heater to EDG 2-1
Jumper 98-013, (Unit 2) (LBIE Log No. 98-010)

Since Bus F was out of service for maintenance, the power supply to the emergency diesel generator (EDG) lube oil Heater Panel MPF-28 was cleared. In order to maintain lube oil temperature above 90°F, the lube oil heater had to be energized from adjacent Panel MPG-31 using a jumper.

Safety Evaluation Summary

Energizing the lube oil heater from another power source (in this case, its own train) would not have an impact on the accidents evaluated in the FSAR Update. In case of an electric fault associated with this jumper, the supply breaks would clear the fault. Technical Specifications require one operable EDG in Modes 5 and 6. This was satisfied with EDGs 22 or 23. Based on the above criteria and justification, an unreviewed safety question is not involved. Also, a change to the Technical Specifications is not involved.

9. Temporary Modifications/Plant Jumpers
Jumper 98-06, Rev. 1 (Unit 1) (LBIE Log No. 97-042)

The vibration loose parts monitor (VLPM) channel 6 input lead was lifted to prevent excessive nuisance alarms that had been occurring since the Unit 1 seventh refueling outage. Although the input had been taken off scan per Procedure OP1.DC24, the alarms were still coming in to PK 11-11. The lead will remain lifted until the source of the alarms can be determined during the next outage.

Safety Evaluation Summary

This 10 CFR 50.59 safety evaluation was prepared because steam generator (SG) 1-1 VLPM redundancy, as described in the FSAR Update, was reduced

from 2 to 1. Also, actions described in the FSAR Update that occur when an individual transducer channel exceeds an adjustable setpoint were modified.

The VLPM provides early detection of potential loose parts in the reactor coolant system (RCS) so remedial action may be taken before damage occurs. With one SG 1-1 VLPM channel disabled, one channel remains. The loose parts monitoring computer software has been adjusted to provide an alarm on the one remaining input. The resulting loose parts alert capability is more conservative in this configuration because both channels must read high to initiate an alarm with two channels available. The probability of an accident or equipment malfunction caused by the lifted input lead will not contribute to an increased accident or equipment malfunction frequency because SG 1-1 loose parts monitoring capability is maintained more conservatively than described in the FSAR Update.

The VLPM is a Class II monitoring system that is not required to mitigate the consequences of any FSAR Update accident or equipment malfunction. This jumper does not raise the consequences of any evaluated accidents or equipment malfunctions in which loose parts are monitored, whether the loose parts contribute to the accident or not.

VLPM operability is controlled by Equipment Control Guideline (ECG) 46.1. VLPM function is maintained. No margins of safety for this system are described in the ECG bases or the FSAR Update.

10. Determinate Defective Pressurizer Heaters
MMP M000059, Rev. 1 (Unit 2) (LBIE Log No. 97-028)

Maintenance Modification Package (MMP) M000059 allows defective pressurizer heaters to be disconnected. This allows the remaining heaters fed from the same circuit breaker to be returned to service. The initial pressurizer heater capacity was 1800 kW. This MMP allows failed heaters to be disconnected as long as total capacity of at least 1340 kW with Heater Groups 1 and 4 each having at least 276 kW and Groups 3 and 4 each having at least 345 kW is maintained.

Safety Evaluation Summary

The pressurizer heaters are nonsafety related. The purpose of the pressurizer heaters is to control pressurizer pressure during heatup and power operation and to support natural circulation of the reactor coolant system during the loss of offsite power. 150 kW is required to support natural circulation. Technical Specifications define the minimum pressurizer heater capacity as 150 kW from two groups which can be supplied by vital emergency power. This MMP maintains this 150 kW by limiting the number of heaters that can be disconnected. Therefore, all margins of safety implicit in this Technical Specification requirement are maintained by this MMP.

11. Main Feedwater Overspeed Trip Test
Jumper PEP-04R, Rev. 5A (Units 1 & 2) (LBIE Log No. 98-036)

The overspeed trip test is normally performed using main steam. This revision of the procedure makes it acceptable to use a cross-tie to the auxiliary steam system to warm up and overspeed the turbine. The overspeed trip test is performed with the main feedwater pump uncoupled regardless of the source of the turbine steam supply.

Safety Evaluation Summary

The overspeed trip test is performed with the main feedwater pump uncoupled and out of service. The use of an alternate supply of motive steam does not create a new accident or potential malfunction. The potential failure of the jumper is bounded by a break in the auxiliary steam header.

12. Operation of the Component Cooling Water (CCW) System to Support Replacement of Temperature Control Valve (TCV)-130
TP T0-9705, Rev. 0 (Unit 1) (LBIE Log No. 97-088)

This temporary procedure was prepared to support replacement of CCW temperature control valve TCV-130. Due to a leaking return isolation valve, leak tight isolation of the line was not possible. To replace TCV-130, restriction orifice RO-239 had to be replaced with a blank plate so the bypass line would pass flow. It was necessary to establish a bleed path downstream of RO-239 to relieve pressure on the orifice so that its flange could be disassembled and the blank plate installed. New bypass isolation valves were added using a hot tap procedure that was also used to establish the bleed path.

This procedure provided instructions to establish the bleed path from the CCW system and regulate makeup flow during the activities associated with RO-209.

Safety Evaluation Summary

The vital portions of the CCW system are designed to mitigate the consequences of an accident by removing heat from the primary system and transferring it to the ocean. The probability of FSAR Update Chapter 15 accidents is not affected by CCW system operation. The consequences of FSAR Update Chapter 15 accidents are not increased provided CCW system operation is maintained. The temporary procedure provided for manual makeup to maintain CCW surge tank level in the normal range. The bleed rate was within the makeup capability of the makeup water system. The RCS was depressurized or at very low pressure during the maintenance operation to minimize leakage of radioactive contamination. Operation of the CCW system was not significantly affected by this procedure; consequences of analyzed accidents and equipment malfunctions were not increased. No new accidents or equipment malfunctions were created. Adequate inventory was maintained in the CCW surge tank. Technical Specification 3.7.3.1 and its bases were not challenged by this procedure.

13. Installing Turbine Building Siding Near High-Voltage Lines and Equipment
TP TA-9701, Rev. 0 (Unit 1) (LBIE Log No. 97-034)

This temporary procedure was written to guide and control re-siding installation activities during the Unit 1 eighth refueling outage. Re-siding the northeast corner of the turbine building involves work near energized high-voltage sources. The Unit 2- 230-kV and 500-kV lines were energized during work near the 500-kV lines. The work was performed with a combination of suspended scaffolding and manlifts. The 230-kV and 500-kV lines are close together; additional controls were needed to ensure personnel and equipment safety.

Safety Evaluation Summary

This evaluation was performed to evaluate the implementing methods and equipment used for the re-siding work and to verify that failure of the methods and equipment would not affect safety-related equipment and safe plant operation.

Suspended scaffolding was evaluated for lifts over restricted areas, seismic interaction issues, personnel safety and operational loads to ensure structural integrity during installation and operation. Deployment and operation of the 175-ton boom crane and mobile manlifts were in compliance with all applicable procedures. Crane ground path, swing path, and station points were evaluated and documented. Cranes and manlifts were evaluated for tipping issues. Electrical observers were stationed during the work. Crane operators were trained and qualified per ANSI/SIA 92.5. Accident possibility and probability were not increased.

Installation and operation of the equipment as described above will not affect safety-related equipment. Heavy loads were not lifted over exclusion areas. Equipment malfunction possibility, probability, and consequences were not increased.

14. Providing Vital 125 Vdc Power from SD 12 to SD 13 Vital Loads
TP TA-9702, Rev. 0 (Unit 1) (LBIE Log No. 97-035)

This temporary procedure provided instruction to install a Class 1E jumper from dc Bus 12 to power 4-kV Bus H and its associated safeguards relay board in Modes 5 or 6. Normally, dc Bus 13 powers up these loads. However, dc Bus 13 was unavailable because its battery was being replaced. The reconfiguration of vital dc control power enabled dc power from dc Bus 12 to power diesel generator (DG) 12 and associated 4-kV Bus G, and DG 11 and associated 4-kV Bus H.

Safety Evaluation Summary

This temporary configuration was implemented for Modes 5, 6, or while defueled in the Unit 1 eighth refueling outage. Class 1E jumpers from dc Bus 12 to the 4-kV Bus H and it associated safeguards relay board were provided. DG 11 did not require jumpers as it is provided with a dc power transfer switch, which was selected to dc Bus 12. All applicable Technical Specifications and Outage Safety Plan requirements were met. The basis for allowing this temporary configuration was based on the following:

- Battery 12 was shown to have capacity to simultaneously operate both 4-kV buses (G and H) and start both DGs (12 and 11).

- The jumper met class IE requirements and did not introduce new failure modes.

- While operating in Modes 5, 6 or defueled, it is not necessary to postulate a single failure of the cross-train Class IE equipment.

15. Replacement of Auxiliary Transformer 2-1
TP TB-9721, Rev. 1 (Unit 2) (LBIE Log No. 98-020)

This temporary procedure addresses the replacement of auxiliary transformer 2-1 (UAT21). The replacement of UAT21 requires use of a crane and trailer. The process could make startup transformer (SUT) 22 and its deluge system a seismically induced systems interaction (SISI) target. During the Unit 2 eighth refueling outage, the SUT 22 provides offsite power to the vital 4-kV and 480-V ac loads.

Safety Evaluation Summary

In Modes 5 and 6, Technical Specifications require one offsite power source and one emergency diesel generator (EDG) be operable. In the event of failure of SUT 22, the EDG will provide power to the vital loads. During load lifting, the crane and its boom will not be oriented in line with SISI targets and located at a distance that minimizes potential for damage to SUT 22.

There is no inservice equipment important to safety in the area where this activity is performed. Vital 4-kV switchgear is inside the turbine building and damage to the nonvital SUT 22 will not affect the vital Bus E or DG safety function. The safety margin is not affected by this activity since the plant will be in Mode 5 or 6 and the outage safety plan addresses the requirements for power availability.

16. Moving Unit 2 Auxiliary 21 Transformer
TP TB-9721, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-017)

This temporary procedure was used to cover the drayage procedure used by Bragg Crane & Rigging Co. to move the old Auxiliary 21 Transformer out of the protected area and the new UST Auxiliary 21 Transformer from Lot 1 into the protected area.

Safety Evaluation Summary

Replacement of the Auxiliary 21 Transformer required the use of a skid system, a 200-ton crane and a transportation trailer. The work was done during Modes 5 and 6 in the Unit 2 eighth refueling outage and in the vicinity of Startup Transformer 22. The transformers were moved fully dressed and filled with oil. This temporary procedure addressed precautions taken to keep the Startup Transformer and its deluge system operational and also addressed the environmental concerns associated with an oil spill or a fire, and the impact on the Emergency Plan.

17. Implementation of DCP E-49297 Battery 13 Replacement
TP TD-9703, Rev. 0 (Unit 1) (LBIE Log No. 97-039)

This temporary procedure provided instruction to install a nonClass 1E jumper from nonvital Battery 17 to provide power to selected dc Bus 13 loads during the Unit 1 eighth refueling outage. Normally vital 125-Vdc Distribution Panel 13 loads are powered from vital Battery 13. However, due to Battery 13 replacement during the Unit 1 eighth refueling outage, selected Class 1E loads were powered via a nonvital jumper from nonvital Battery 17. The jumpers were necessary to keep SD 13 loads operational and support outage related activities.

Safety Evaluation Summary

This temporary configuration was implemented during Modes 5, 6, or while defueled in the Unit 1 eighth refueling outage. NonClass 1E jumpers from Battery 17 to selected dc Bus 13 loads were provided. The basis for allowing this temporary configuration was based on the following:

- Nonvital Battery 17 was determined to have adequate capacity to power up the selected Class 1E jumpered loads. The circuit breakers and jumpers used in the jumper scheme were evaluated and sized and coordinated for the selected loads.

- The nonvital jumper scheme did not introduce new failure modes or create a different type of accident.

- Only those selected loads whose design classification was non-Q were able to be declared operable. The rest of the loads, even though energized by the temporary jumpers, were declared inoperable and no credit was taken to meet Technical Specification limiting condition for operation requirements.

18. Providing Vital 125 Vdc Power from SD 22 to SD 23 Vital Loads
TP TD-9802, Rev. 0 (Unit 2) (LBIE Log No. 97-184)
TP TD-9803, Rev. 0 (Unit 2) (LBIE Log No. 97-190)

This temporary procedure provided instructions for jumpering vital SD 23 loads to SD 22 for the Battery 23 replacement during the Unit 2 eighth refueling outage.

Safety Evaluation Summary

During the vital Battery 23 replacement in the Unit 2 eighth refueling outage, selected Class 1E loads that were vital to Mode 5 or 6 safety were fed from vital Battery 22. This configuration was reviewed with the Outage Safety Plan and found to not increase the probabilities or consequences of any Mode 5 or 6 accidents previously evaluated in the FSAR Update. No unreviewed safety questions were identified.

19. Energize Unit 1 12-kV Startup Bus from Auxiliary Transformer 11
TP TO-9701, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-055)

This temporary procedure (TP) energizes the Unit 1 12-kV startup bus from Auxiliary Transformer 1-1 and clears Startup Transformer 1-1 for replacement and Startup Transformer 1-2 for maintenance. Loss of offsite power to the operable 4-kV vital buses is the only impact possible from this alignment.

Safety Evaluation Summary

Temporary Procedure (TP) TO-9701 is to be performed in Modes 5 and 6. In these modes, analyzed accidents that may be affected are fuel handling accidents, tank ruptures, and the boron dilution event. Loss of offsite power does not cause or affect mitigation of fuel handling accidents since containment isolation does not require offsite power, nor does the fuel handling building (FHB) ventilation system. Loss of offsite power has no effect on tank ruptures. Loss of offsite power does not affect the ability to secure the primary water makeup pumps - the limiting boron dilution event. A loss of offsite power is mitigated by the emergency diesels starting and assuming the vital bus loads. This temporary procedure has no effect on the ability of the Technical Specification and Outage Safety Plan required emergency power sources. Thus, there is no potential unreviewed safety question.

C. Procedure Changes

1. Core Operating Limits Report (COLR) for DCPP Unit 2, Cycle 9
COLR 2-9, Rev. 0 (Unit 2) (LBIE Log No. 98-026)

This report was performed for the initial issue of COLR 2-9. The COLR for Unit 2 Cycle 9 is the same as for Unit 2 Cycle 8 with the exception of W(z) factors that are cycle specific. Because the safety evaluation was performed by a vendor that is not Plant Staff Review Committee (PSRC)-approved, the answer to Question no.4 for the 50.59 screen on the LBIE Screen was "yes."

Safety Evaluation Summary

The safety evaluation performed for this report is the same as the one performed for the Design Change Package (DCP) N-050368, Rev. 0. That evaluation found that there are no adverse consequences to components or systems due to this core reload design. No new performance changes or demands on other components or systems are introduced by this core design.

2. Using Five-Year Average X/Qs in OffSite Dose Calculations
CAP A08, Rev. 20 (Units 1 & 2) (LBIE Log No. 96-044)

FSAR Update Section 11.3.7 assumed historical annual average X/Q values for calculating dose from normal operations for the licensing basis. Procedure CAP A-8 uses historical five-year average X/Q values for calculating dose under the same conditions.

Safety Evaluation Summary

10 CFR 50, Appendix I, states design objectives and limiting conditions for operation of for nuclear power reactor effluents. Limits to meet these conditions are implemented by Technical Specification 6.8.4.6.

FSAR Update Section 11.3 states the results of a pre-operational analysis for the estimated gaseous effluents and dose during normal operation. The analysis was performed to demonstrate that the criteria of 10 CFR 50, Appendix I, can be met. This analysis assumed annual average X/Q conditions. PG&E believes the calculated dose is the licensing basis.

Procedure CAP A-8, "Offsite Dose Calculations," implements the methodology used during normal plant operations to ensure compliance with 10 CFR 50, Appendix I, and the Technical Specification requirements. CAP A-8 uses five-year historical average X/Q values to calculate radioactive gaseous effluent dose and these values are used as one of the variables to calculate radioactive effluent and radioactive process monitor high alarm setpoints (HASP). The HASP values are used to ensure the dose rate limits are not exceeded. The

dose rate limits are a fixed value. Therefore, as X/Q values increase, the release rate decreases to maintain the dose rate limit. As X/Q decreases, the release rate limit may increase up to the dose rate limit. Thus, HASP's determined by CAP A-8 account for X/Q variations and ensure dose rate limits are not exceeded.

Five-year historical average X/Q values are more representative of average DCPP meteorology conditions than historical average X/Q values (used in the FSAR Update Section 11.3 analysis). The five-year historical average X/Q values may, in any given year, be more or less than the corresponding annual average values as stated as "estimates" in the FSAR Update analysis.

In the current revision 20 of Procedure CAP A-8, the historical five-year X/Q values are less than those in the FSAR Update Section 11.3 analysis. The values used in the analysis are listed in Table 11.3-11, " Estimates of Relative Concentration X/Q at Locations Specified in Table 11.3.-10."

An FSAR Update change to include the use of five-year historical meterological data to calculate X/Q values has been submitted.

3. Offsite Dose Calculations
CAP A-8, (Units 1 & 2) (LBIE Log No. 97-083)

The Offsite Dose Calculation Process (ODCP) X/Q and D/Q values are updated yearly based upon the latest five-year meteorological data. The FSAR Update also lists X/Q and D/Q values. The issue is how does the ODCP X/Q and D/Q revisions impact the FSAR Update values.

Safety Evaluation Summary

10 CFR 50.34a requires nuclear power plants to be designed in such a way that doses due to routine effluent releases not exceed the 10 CFR 50, Appendix I, dose design objectives. The X/Q and D/Q values listed in the FSAR Update, Section 11.3, are used for pre-operational demonstration of compliance with the 10 CFR 50.34a design criteria and, therefore, represent design bases for licensing. For purposes of demonstrating the design criteria, dose pathways and locations are assessed that are not utilized for routine effluent control. The actual dose pathways and locations used for routine effluent controls are based on the annual land use census information, as well as concurrent (latest five-year annual average) meteorological data.

Thus, the FSAR Update X/Q and D/Q values, which are used for 10 CFR 50.34a calculations, are unrelated to the X/Q and D/Q values used for routine effluent dose assessment.

4. Pilot Process Instruction Development
AD1.ID8, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-033)

This is a new procedure that provides requirements and supplemental guidance for developing instructions to control pilot processes. This procedure is in support of the Work Control Process reengineering effort.

Safety Evaluation Summary

This procedure controls how administrative instructions are written and does not directly control activities in the plant, nor does it directly control operation of equipment important to safety. This procedure does not interact with any specified margin of safety as defined in any Technical Specification.

5. Control of the Surveillance Testing Program
AD13.DC1, Rev. 4 (Units 1 & 2) (LBIE Log No. 97-207)

This revision of Procedure AD13.DC1 adds the manual vents and drains between the inner and outer containment isolation valves. The NRC recently rovided additional clarification as to the applicability of Technical Specification (TS) 4.6.1.1a in relation to which penetrations were considered “in service” during accident conditions. License Amendment 73 and 72 relocated TS Table 3.6-1, “Containment Isolation Valves,” to the Diablo Canyon Power Plant Procedures that are subject to the change control provisions in the administrative controls section of the TS. Any change to the containment isolation valve list would constitute a change to the facility and thus would be subject to the provisions of 10 CFR 50.59.

Safety Evaluation Summary

The change is administrative in nature. The change should improve administrative practices without any effect on plant operations. Improved administrative practices increase the likelihood the valves will be maintained closed, thereby improving mitigation potential.

6. Control of the Surveillance Testing Program
AD13.DC1, Rev. 5 (Units 1 & 2) (LBIE Log No. 98-032)

License Amendment Request (LAR) 91-08 proposed relocation of Technical Specification (TS) Table 3.6-1, “Containment Isolation Valves,” to the DCPP procedures that are subject to the change control provisions in the administrative controls section of the TS. This revision of AD13.DC1 adds VAC-2-540 to Attachment 7.7, “Containment Isolation Valves.” This change does not affect the FSAR Update.

Safety Evaluation Summary

This change is administrative in nature and should result in improved administrative practices without any effect on plant operations. The change does not result in any physical modifications and does not alter the method by which any safety-related system performs its function.

Adding VAC-2-540 to the list increases assurance containment integrity is maintained. Improved administrative practices increase the likelihood the valves will be maintained closed, thereby improving mitigation potential.

7. Outage Safety Management of Increased Risk Periods Including Hot Mid-Loop Operations
AD8.DC52, Rev. 4 (Units 1 & 2) (LBIE Log No. 98-018)

This evaluation addressed programmatic issues to incorporate hot mid-loop operations into outage nuclear safety management strategies. Specifically, it addressed a change to a policy statement regarding avoidance of mid-loop operations with fuel in the reactor vessel, and a change in the configuration of the reactor coolant system (RCS) prior to entering reduced inventory operations.

Safety Evaluation Summary

There are no FSAR Update accidents postulated for shutdown events other than a misplaced fuel assembly or fuel handling accident for which this change has no effect.

Changing the authorization process for mid-loop operation, and keeping the reactor head tensioned prior to reduced inventory conditions do not adversely affect RCS or support system hydraulics, heat transfer, pump operation, safety analyses or Technical Specification bases.

The final approval for mid-loop operation still remains with the Vice President and Plant Manager, DCPP. The Vice President and Plant Manager, DCPP is responsible for, and has control over, unit safe operation per the Technical Specifications, FSAR Update Chapter 13, and implementing Program Directives.

Allowing the reactor head to remain tensioned prior to reduced inventory operation does not affect any RCS system in use during shutdown conditions. None of the functions of the residual heat removal system or other systems required for shutdown operations are affected by having a tensioned reactor vessel head prior to reduced inventory conditions.

8. Core Offload Sequence
OP B-8DS1, (Unit 2) (LBIE Log No. 98-019)

Action Request (AR) A0454011 describes an event that occurred during core offload for the Unit 2 eighth refueling outage, stemming from an indeterminate crane failure. Due to the inability to specifically identify the failed component or condition, it was decided to develop an action plan and cautiously proceed.

Safety Evaluation Summary

The crane functions of overload/underload/slack cable still function and are not questioned. The hoist features are separate from the crane lateral movement and overload setpoint features. The gripper and motor failure features are fail-safe and function normally. The event described has no impact on the safety features inherent in the crane design. The safety features, as described in the FSAR Update and Technical Specifications, remain operable, and the inherent safety provided by them is maintained. The Technical Specification requirements remain satisfied in this event and action plan. There is no reduction in margin of safety.

9. OP C-7C:VI, "Transferring/Offloading Sulfuric Acid and Ammonium Hydroxide"
OP C-7C:VI, Rev. 10 (Unit 1) (LBIE Log No. 97-140)
OP C-7C:VI, Rev. 9 (Unit 2) (LBIE Log No. 97-141)

This procedure change added measures to mitigate a chemical spill when offloading chemicals.

Safety Evaluation Summary

The proposed change blocks potential drainage paths when offloading sulfuric acid or ammonium hydroxide. This warranted an environmental protection plan review under the Licensing Basis Impact Evaluation (LBIE) screening criteria. Since the proposed changes would not add any new discharges, would not require a change to the Environmental Protection Plan, would not change quantities of chemicals used or stored at DCPP, nor add any new hazardous waste streams, no unreviewed environmental question exists.

10. EQ Program Implementation in NTS
DLAP CF3.NE8, Rev. 0A (Units 1 & 2) (LBIE Log No. 97-181)

Section 3.11.1.4 of the FSAR Update, "Class 1E Electrical Equipment Qualification List Maintenance," specified that a hard-copy output (a RAMIS Report) of the DCPP EQ Master List information from PIMS constitutes the DCPP Class 1E Electrical Equipment Qualification List and was maintained as a controlled drawing (PG&E Drawing 050909). This Licensing Basis Impact Evaluation (LBIE) was performed to remove the administrative requirement to issued a hard copy of the EQ Master List from the FSAR Update.

The EQ Master List is now a living list that is comprised of certain fields in the PIMS component database. Therefore, there is no value in unnecessarily issuing Drawing 050909.

Safety Evaluation Summary

This administrative change does not affect the operation of the plant or accident initiation, consequences, or probability. It is an FSAR Update revision to change how the EQ Master List is handled. It was previously issued as a hard-copy drawing on a 6-month frequency. Now it is a living document (in the PIMS component database) that is revised on an ongoing basis. The end result is the Master List is always kept current versus being up to 6 months out of date. All changes to the EQ Master List are reviewed on a 6-month frequency, thereby ensuring the accuracy of the living EQ Master List.

11. Design Change Requests and Design Change Vehicles
CF4.ID1, Rev. 3 (Units 1 & 2) (LBIE Log No. 97-208)

This procedure describes the process for initiating design change requests and selecting an appropriate design change vehicle. The procedure revision introduces a new process for Class N Modifications.

Safety Evaluation Summary

This procedure revision involves Class N Modifications that are defined as being minor in nature, do not change a setpoint, do not affect the DCPP design basis, and are not considered to be design changes. Therefore, there can be no reduction in the margin of safety as defined in the basis for any Technical Specification.

12. Reactor Trip or Safety Injection
EOP E-0, Rev. 19 (Unit 1) (LBIE Log No. 97-025)

Emergency Operating Procedure (EOP) E-0 was modified to add an instruction to place two component cooling water (CCW) heat exchangers in service if the reactor coolant system (RCS) is not intact at step 21 as preparation to transfer to EOP E-1.3. An item was also added to the foldout page to transition to EOP E-1.3 if the refueling water storage tank (RWST) level is less than 33 percent.

The changes were made to reduce the operator response time to EOP E-1.3 when aligning the RCS for cold leg recirculation. The specific location of the instruction was chosen to ensure that it would be performed (i.e., not bypassed due to RNO on other steps), and to minimize potential disruptions in the flow of diagnosing and responding to the accident in progress.

Safety Evaluation Summary

The change affects equipment alignment following a loss-of-coolant accident (LOCA), which is not the cause or initiating event of an accident. There is no change to method of operation for any accident mitigation equipment. The possibility and probability of accidents or equipment malfunctions are not affected. Placing two CCW heat exchangers in service at the subject step improves operator response time to a LOCA and does not affect operator response times to non-LOCA accidents diagnosed by EOP E-0. Accident analysis assumptions are not affected if both CCW heat exchangers are placed in service and transfer to cold leg recirculation is not needed. All safety-related equipment verifications will have been performed before transfer to EOP E-1.3 when the RWST level falls to 33 percent. The consequences of an accident are not affected. The transfer does not affect Technical Specification provisions for ECCS operability and long-term core cooling. Safety margins are not affected.

13. Reactor Trip or Safety Injection
EOP E-0, Rev. 20 (Unit 1) (LBIE Log No. 97-011)
EOP E-0, Rev. 11 (Unit 2) (LBIE Log No. 97-012)

Emergency Operating Procedure (EOP) E-0 was revised such that ECA-0.0 will not be performed if any vital bus is energized. The intent is to cope with loss of ac emergency power until at least one emergency bus can be energized.

Prior to this change, one complete train of emergency core cooling system (ECCS) equipment was required to exit emergency contingency guidelines and return to the recovery and functional restoration (E-series and FR-series) guidelines. The operator was directed to remain in ECA-0.0 with one vital 4-kV bus energized because two buses were required to guarantee restoration of minimum safeguards equipment. However, with power restored to one vital bus, some degree of core cooling becomes available. Westinghouse Direct Work No. 92-033 clearly stated that minimum safeguards capacity is not required to be in the recovery and function restoration guidelines.

This change will allow the operators to fully use the emergency procedure network to mitigate concurrent accidents.

Safety Evaluation Summary

The safety evaluation was performed to evaluate the effect on ECCS equipment and to verify that a failure mode could not be created by implementing the E-series or FR-series emergency procedures with less than one full train of safeguards equipment.

The emergency contingency, recovery, and functional restoration procedures are used to mitigate the consequences of accidents. Their use cannot cause an accident.

All FSAR Update accidents were evaluated and validated for recovery with only one 4-kV bus available. In each case, it was determined that recovery was possible. The revised procedure allowed recovery options that were previously not available. Recovery was not impaired and consequences were not increased.

The change provides improved guidance for the operators when a vital bus is energized. Other procedures are adequate for accident mitigation. Use of the modified procedures does not increase the possibility, probability, or consequences of any equipment malfunction or accident. The margin of safety is not reduced because remaining equipment can be operated optimally to maintain core cooling.

14. Reactor Trip or Safety Injection
EOP E-0, Rev. 10 (Unit 2) (LBIE Log No. 97-026)

Emergency Operating Procedure (EOP) E-0, “Reactor Trip or Safety Injection” was revised to include an action to place two component cooling water (CCW) heat exchangers in service if it is determined that the reactor cooling system (RCS) is not intact and a transition to EOP E-1, “Loss of Reactor or Secondary Coolant,” is required. Placing both CCW heat exchangers in service is done in anticipation of an eventual transition to EOP E-1.3. Placing this action in EOP E-0 is advantageous as it removes the operation from the timeline of cold leg recirculation alignment. Also, the foldout page was revised to instruct the operators to go to EOP E-1.3 immediately if the refueling water storage tank (RWST) level is less than 33 percent.

Safety Evaluation Summary

EOP E-0 provides diagnostic steps to provide the operators with the symptoms and appropriate actions for main steam line break (MSLB), steam generator tube rupture (SGTR), and loss-of-coolant accident (LOCA). It also provides a direct path to terminate a safety injection (SI). The accident analyses for MSLB and SGTR, and the analysis for inadvertent SI assume specific operator response times.

The addition of a step to place both CCW heat exchangers in service following a LOCA does not impact these analyses. Accident mitigation for the LOCA is not adversely affected as the timeline for realignment for cold leg recirculation is improved. If a LOCA is diagnosed and transfer to cold leg recirculation is not needed, alignment of the second heat exchanger does not significantly delay the actions of EOP E-1; therefore, accident analysis assumptions are not altered.

15. Loss of Reactor or Secondary Coolant
EOP E-1, Rev. 14 (Unit 1) (LBIE Log No. 97-022)
EOP E-1, Rev. 8 (Unit 2) (LBIE Log No. 97-023)

This emergency operating procedure revision deletes the step that verifies that the water level in the containment recirculation sump is sufficient to support the operation of the residual heat removal (RHR) pumps in cold leg recirculation. The adequacy of the recirculation sump level to support RHR pump operation is now verified in EOP E-1.3 prior to placing the RHR pumps into service. Delaying the verification until this time allows for more inventory to collect in the sump. This reduces the potential for unnecessarily entering ECA-1.1.

Safety Evaluation Summary

The purpose of checking the level in the containment recirculation sump is to confirm that there is sufficient water available to support the operation of the RHR pumps during cold leg recirculation. Deleting this step from E-1 does not create an unreviewed safety question as this step is now performed in EOP E-1.3 just prior to placing the RHR pumps in service. Delaying this verification step to EOP E-1.3 decreases the potential of inadvertently entering ECA-1.1 due to insufficient sump level. Entering ECA-1.1 unnecessarily would delay the operator's overall response to the event. EOP E-1.3 contains guidance to enter this procedure if sump level is not adequate when the step is reached to place the RHR pumps in service. Additionally, operators are instructed to monitor for RHR pump cavitation.

16. EOP E-1.3, “Transfer to Cold Leg Recirculation”
EOP E-1.3, Rev. 6 (Unit 1) (LBIE Log No. 96-025)
EOP E-1.3, Rev. 5 (Unit 2) (LBIE Log No. 96-026)
EOP E-1.3, Rev. 6 (Unit 2) (LBIE Log No. 97-002)
EOP E-1.3, Rev. 7 (Unit 2) (LBIE Log No. 97-021)

This procedure describes the process of reconfiguring emergency core cooling pumps and valves from the injection phase of a loss-of-coolant accident (LOCA) to the recirculation phase of such an event. This process is described in detail in the FSAR Update, so any changes to that sequence require an evaluation under 10 CFR 50.59. The proposed revisions added a few check and action steps to the process. It should also be noted that this evaluation covered all previous revisions to the procedure, which modified this sequence in various ways, but were not evaluated under 50.59.

Safety Evaluation Summary

The FSAR Update includes a statement that the above described process is completed in “approximately 10 minutes.” As demonstrated analytically and through simulator runs, this sequence could be accomplished in such a time, and the addition/deletion of some of the FSAR Update-described steps does not conflict with that statement. Furthermore, the steps being added/deleted were necessary to assure proper completion of the switchover, and do not result in depletion of the refueling water storage tank (RWST) (which would require termination of injection during a LOCA) before recirculation has begun. Therefore, the modification of the FSAR Update-described sequence does not challenge the operator’s ability to successfully transfer to cold-leg recirculation within the required timeframe in order to mitigate a LOCA. An unreviewed safety question is not involved.

17. Transfer to Cold Leg Recirculation
EOP E-1.3, Rev. 15 (Unit 1) (LBIE Log No. 97-020)
EOP E-1.3, Rev. 7 (Unit 2) (LBIE Log No. 97-021)

This emergency operating procedure revision moves the requirement to check the containment recirculation sump level check to just prior to starting the residual heat removal (RHR) pumps, and to move the requirement to locally close the breakers for the refueling water storage tank (RWST) suction isolation valves to the start of the procedure. Other changes increase the usability and efficiency of the procedure. As a result, the time to switchover is reduced by 45 seconds.

Safety Evaluation Summary

Restructuring the emergency operating procedure (EOP) steps reduces the time required to reach cold leg recirculation. Delaying the verification of the

recirculation sump level reduces the possibility of inadvertently entering ECA-1.1 in response to inadequate sump level. Guidance has been added to ensure that RHR pump cavitation due to inadequate suction is identified, and the procedure continues to direct the operators to take the appropriate action in response to this condition. Improving the timeliness of the switchover to cold leg recirculation ensures that the design basis for the emergency core cooling system is maintained during realignment.

18. Transfer to Cold Leg Recirculation
EOP E-1.3, Rev. 14 (Unit 1) (LBIE Log No. 97-001)
EOP E-1.3, Rev. 6 (Unit 2) (LBIE Log No. 97-002)

This revision added steps to accentuate the need for timeliness and to allow certain steps to be performed in parallel. The evaluation also covered all past revisions to Emergency Operating Procedure (EOP) E-1.3 since safety evaluations were not performed for some revisions or were considered to be inadequate for others.

Safety Evaluation Summary

FSAR Update Tables 6.3-4 and 6.3-5 and Sections 6.3.1.4.4.2, 6.3.1.4.4.3, and 6.3.2.17 describe the process of transfer from the emergency core cooling system (ECCS) injection mode to the cold leg recirculation mode of operation after a loss-of-coolant accident (LOCA). Table 6.3-5 contains the basic sequence of operations to establish cold leg recirculation. Certain steps of EOP E-1.3 have been modified such that the sequence of operations is somewhat different than that described in the FSAR Update.

The following steps have been added to EOP E-1.3 that do not appear in FSAR Update Table 6.3-5:

- Step 3.d, which verifies the ASW/CCW is aligned for two ASW pumps through two heat exchangers

- Steps 5.d.3) and 7.f.3), which verify decreasing the RHR heat exchanger outlet temperatures after their respective RHR pumps have been started

- Step 6.a, which closes the CCP recirculation valves 8105 and 8106

- Steps 6.d. and 6.g.2), which throttles the RHR heat exchanger outlet valves when the RHR pumps begin supplying suction flow to the SI and CCPs

Additionally FSAR Update Table 6.3-5 identifies Valves 8701 and 8702 as being checked closed in order to provide RCS to RHR suction isolation. This is not explicitly done in EOP E-1.3, since these valves are maintained closed in Modes 1-3.

FSAR Update Section 6.3.1.4.4.2 states that the total time for the changeover from injection to recirculation is approximately 10 minutes, as shown in Table 6.3-5. The purpose of FSAR Update Table 6.3-5 is to provide a guideline for the emergency operating procedures to accomplish the transfer to cold leg recirculation in approximately 10 minutes. The importance of the 10 minutes is to ensure that there is adequate water inventory in the refueling water storage tank (RWST) for the continuous cooling to the core/containment by the centrifugal charging pumps (CCPs), safety injection pumps (SIPs), and containment spray pumps (CSPs). The transfer to cold leg recirculation must be completed prior to running out of inventory in the RWST.

Emergency Procedure (EP) EOP-1.3, Rev. 0, contained a step that checked the position of several MOVs and a step to locally close breakers for Valves MOV 8980 and MOV 8976. It is assumed that an operator would be dispatched to close these breakers at that step, and at the point closing the valves is requested, it would have been accomplished. There is adequate time in the procedure as detailed in FSAR Update Table 6.3-4A for this to occur. It should

be noted that in the current revision of EOP E-1.3, this action is moved to step 9.b.2, which is after the transfer to cold leg recirculation is completed. Neither of these two items would have an appreciable impact on the ability to complete the transfer in approximately 10 minutes. This review is considered to bound all the past revisions of EOP E-1.3 up to and including Revision 14.

The stated transfer time to cold leg recirculation of 10 minutes is an informational guideline as stated in the FSAR Update by the use of the term “approximately 10 minutes.” The 10 minutes is considered a guideline since considerable margin exists in the assumptions in the table for ECCS pump flows and useable volume in the RWST between the low-alarm RHR pump trip level and the low-low alarm level (4 percent). Simulator validation with randomly selected operating crews demonstrated that the transfer to cold leg recirculation could be accomplished in the required timeframe. Results of that simulator testing are documented in AR A0416238.

In Revision 0 of EP E-1.3, dated March 11, 1985, closure of motor-operated Isolation Valves SI-8805A/B, 8976, and 8980 were moved to the nontime-critical part of the procedure, i.e., after both RHR pumps were aligned to the suctions of the CCP and SI pumps. There is no discussion in the procedure history sheets as to why this change was made, although it may have been due to a single failure analysis of an RHR pump after the first RHR pump is aligned to the suction of the SI pumps, and the resulting loss of SI flow if the 8976 valve were closed.

Several NCRs and ARs have discussed check valve testing and design basis in the past: NCRs DC0-91-TN-N026, DC0-93-TP-N028, DC0-93-TS-N042, and DC0-93-NS-N002, ARs A0351369, A0291455, and A0315425.

Operation of the Check Valves SI-8924, 8977, and 8981 in these lines can be credited. The functional description of these valves for the Inservice Testing (IST) program is contained in NPG Calculation N-124. This calculation was prepared in response to NCR DC0-93-TP-N028, to define the IST testing criteria and basis for check valves. N-124 states for each of these valves: "This valve has a safety function for a short period of time in the closed direction to prevent the discharge of potentially highly radioactive post-LOCA containment recirculation sump water to the RWST during the switchover from the injection phase to the cold leg recirculation phase of safety injection."

The post-LOCA recirculation leakage calculated limit into the RWST per Calculation N-169 and N-170 is 11.26 gpm. These calculations were performed to evaluate the consequences of leakage of post-LOCA recirculation fluid to the RWST. Whole body and thyroid doses to the control room, exclusion area boundary, and low population zone were calculated. It was concluded that the contribution to the dose from recirculation loop leakage to the RWST is negligible for any leakage that is likely to result from check valve leakage.

As a result of the above discussions, it was acceptable to move the closure of the RWST motor-operated valves to the nontime-critical part of EOP E-1.3. It is further acceptable that certain actions be performed outside the control room due to concerns raised relative to spurious actuation. Neither the consequences nor the likelihood of an accident are increased by these changes.

19. Transfer to Hot Leg Recirculation
EOP E-1.4, Rev. 11 (Unit 1) (LBIE Log No. 97-005)

This procedure revision removes the requirement for auxiliary saltwater (ASW) train separation. A requirement was added to contact the Technical Support Center (TSC) for an evaluation of train separation and component cooling water (CCW) train separation, contingent upon TSC direction to do so.

Safety Evaluation Summary

This procedure revision provides greater flexibility in responding to an active failure while allowing train separation to mitigate a passive failure after the first 24 hours. All affected items are used to mitigate an accident and are not considered as initiators of any accident. Therefore, there are no adverse consequences of this revision.

20. Transfer to Hot Leg Recirculation
EOP E-1.4, Rev. 4 (Unit 2) (LBIE Log No. 97-006)

Emergency Operating Procedure (EOP) 1.4 was revised so that component cooling water (CCW) and auxiliary saltwater (ASW) train separations are not required following transfer to hot leg recirculation. With both systems aligned to separate trains as required by the previous EOP revision, there was a concern that a postulated of loss of Bus F power would cause loss of containment heat removal due to loss of flow in one train and loss of ASW flow to the other CCW train. The procedure change allows realignment of ASW and CCW into separate trains to be performed after transfer to hot leg recirculation as directed by the Technical Support Center.

Safety Evaluation Summary

This 10 CFR 50.59 safety evaluation was performed because the description of ASW and CCW train separation as described in FSAR Update Section 9.2.2, Table 9.2-7, and Section 9.2.7.2 was changed to remove the requirement for train separation following transfer to hot leg recirculation. At the same time, train separation is not prohibited as a long-term recovery action if plant configuration and operating conditions warrant the action.

Separation of the CCW and ASW trains following transfer to hot leg recirculation is a long-term recovery action following an accident, and is not related to the cause of an accident or equipment malfunction. The changes affect accident mitigation by providing greater flexibility in responding to an active failure. Train separation to mitigate a passive failure after the first 24 hours is still allowed. These actions can be taken within the timeframe specified in the FSAR Update. Consequences of an evaluated accident are not increased.

21. Revision to Emergency Operating Procedure for Transfer to Hot Leg Recirculation
EOP E-1.4, Rev. 13 (Units 1 & 2) (LBIE Log No. 97-008)

This operations emergency procedure gives the necessary sequence of steps to maintain long-term core cooling following a loss-of-coolant accident (LOCA). This procedure is implemented during the first day following an accident and it limits precipitation of coolant boron onto cores surfaces that could degrade fuel rod heat transfer.

Safety Evaluation Summary

The revision was made to address the possibility that the loss of a single vital ac power source to safety-related equipment could interrupt emergency core cooling if redundant trains of cooling are physically separated (a method for passive failure protection during the long-term core recovery process). The decision to separate trains now belongs to the site emergency organization (Technical Support Center) and will be based upon the plant conditions that exist at that time. Other alternatives for passive failure protection remain available.

22. Testing and Maintenance of Battery Pack Emergency Lights Inside Power Block
MP E-67.5A, Rev. 15 (Units 1 & 2) (LBIE Log No. 97-030)

Revised maintenance procedure to combine all battery-operated light (BOL) testing into one procedure (was previously contained in Surveillance Test Procedure (STP) M-17C1/C2A/C2B).

Safety Evaluation Summary

Testing of BOLs was previous performed using Surveillance Tests (M-17C1, M-17C2A, M-17C2B) and will now be performed by a Maintenance Procedure (MP E-67.5A). This differs from commitments described in FSAR Update Appendix 9.5B, Section C.5, which states, "Test programs are laid out in detail in surveillance test procedures and are controlled by the QA Manual…." and "Procedures governing periodic inspections are laid out in the surveillance test procedures." Change from STP to MP will require a change to the Fire Protection Plan as described in the FSAR Update. This LBIE supports the use of MP for testing and inspection.

23. Loss of All Vital AC Power
EOP ECA-0.0, Rev. 11 (Unit 1) (LBIE Log No. 97-009)

Emergency Operating Procedure (EOP) ECA-0.0 was written to address the loss of all vital ac power. It has been revised such that it may now be exited when a single vital bus is energized. The previous operating philosophy required that a complete train of emergency core cooling system equipment be restored prior to exiting ECA-0.0. The change in philosophy is supported by the Westinghouse Owner's Group determination that the availability of minimum safeguards capacity is not a requirement for being in other optimal recovery guidelines and function restoration guidelines.

Safety Evaluation Summary

The total loss of vital ac, as well as the loss of two vital buses, is beyond the single failure design basis of DCPP. Modification of EOP ECA-0.0 to allow operators to return to the recovery guidelines (E and FR series procedures) when one vital bus has been restored improves the ability to cope with this beyond design basis accident. The modification of this post-accident response procedure does not increase the probability or possibility of an accident. The purpose of ECA-0.0 is to respond to multiple failures. Exiting the procedure with only one vital bus does not ensure that further malfunctions are prevented; however, the use of the full network of emergency procedures improves the overall response to the postulated plant condition.

24. Loss of All Vital AC Power
EOP ECA-0.0, Rev. 6 (Unit 2) (LBIE Log No. 97-010)

Emergency Contingency Guideline ECA-0.0 was revised such that it will not be performed if any vital bus is energized. The intent is to cope with loss of ac emergency power until at least one emergency bus can be energized.

Prior to this change, one complete train of emergency core cooling system (ECCS) equipment was required to exit emergency contingency guidelines and return to the recovery and functional restoration (E-series and FR-series) guidelines. The operator was directed to remain in ECA-0.0 with one vital 4-kV bus energized because two buses were required to guarantee restoration of minimum safeguards equipment. However, with power restored to one vital bus, some degree of core cooling becomes available. Westinghouse Direct Work No. 92-033 clearly stated that minimum safeguards capacity is not required to be in the recovery and function restoration guidelines.

This change will allow the operators to fully use the emergency procedure network to mitigate concurrent accidents.

Safety Evaluation Summary

The safety evaluation was performed to evaluate the effect on ECCS equipment and to verify that a failure mode could not be created by implementing the E-series or FR-series emergency procedures with less than one full train of safeguards equipment.

The emergency contingency, recovery, and functional restoration procedures are used to mitigate the consequences of accidents. Their use cannot cause an accident.

All FSAR Update accidents were evaluated and validated for recovery with only one 4-kV bus available. In each case, it was determined that recovery was possible. The revised procedure allowed recovery options that were previously not available. Recovery was not impaired and consequences were not increased.

The change provides improved guidance for the operators when a vital bus is energized. Other procedures are adequate for accident mitigation. Use of the modified procedures does not increase the possibility, probability, or consequences of any equipment malfunction or accident. The margin of safety is not reduced because remaining equipment can be operated optimally to maintain core cooling.

Commitments to the NRC regarding maintenance of core cooling with ac power unavailable are maintained.

25. Service Cooling Water - Alternate Cooling Supplies to SCW Heat Exchangers
OP F-1:VI, Rev. 3 (Units 1 & 2) (LBIE Log No. 97-058)

Per the FSAR Update, saltwater is the cooling medium for the service cooling water (SCW) heat exchangers. This procedure revision allows firewater to supply cooling to the SCW heat exchangers as an alternate source during outages when the circulating water system is shut down and the auxiliary header is cleared.

Safety Evaluation Summary

During the time firewater is used to cool the SCW heat exchangers, the unit secondary side is in an outage condition. The SCW system has no effect or impact on the plant safety at this time. The low operating pressure and temperature of the system minimize the probability of line failure.

At the time firewater is used as alternate cooling, there is no safety-related equipment in the area. The firewater hose reel system is a seismically qualified system that can be isolated by sectionalizing within the plant. The physical location of lines and components cooled by the system is such that the failure would not affect any safety-related Design Class 1 equipment or components.

26. Makeup Water Sources to the CCW System
OP F-2:VII, Rev. 1 (Unit 1) (LBIE Log No. 97-131)

Instructions were added to the operating procedure to use the firewater storage tank (FWST) contents to supply the component cooling water (CCW) system if needed. The use of the FWST for CCW makeup is described in FSAR Update Section 9.2.2.3.3. Prior to this revision, such usage was not addressed in an operating procedure.

Safety Evaluation Summary

The procedure change does not affect the status of any plant system prior to an accident. The FWST is used for CCW makeup only after failure of the CCW system and several other makeup sources. The specific alignment is not associated with any FSAR Update accident; it adds an additional backup source of CCW makeup and adds flexibility to the ability of operations to mitigate FSAR Update-analyzed accidents concurrent with certain failures. Accident and equipment malfunction probabilities and consequences are not increased.

27. Makeup Water Sources to the CCW System
OP F-2:VII, Rev. 1 (Unit 2) (LBIE Log No. 97-132)

The procedure was revised to include the specific steps to align the firewater storage tank as a backup source to the CCW system, as described in the FSAR Update. The revision also requires the concurrence of Chemistry and Environmental Operations prior to using the primary water storage tank as a backup source for CCW makeup.

Safety Evaluation Summary

The changes to the procedure ensure that alternate supply sources of makeup water for the CCW system are available. The availability of backup supplies increases the reliability of the CCW system. The alignment of the backup source is already described in the FSAR Update; therefore, this change does not increase the probability or consequences of an accident or malfunction. The consequences of a potential breach of the CCW system are reduced by the flexibility of the multiple backup water sources.

28. Chemistry Control Limits and Action Guidelines for the Secondary Systems
OP F-5:II, Rev. 19 (Unit 1) (LBIE Log No. 98-037)

This procedure revision proposes to use pyrrolidine, as a pH control agent, for chemical injection into the Unit 1 secondary system during operation. Currently the procedure specifies that ethanolamine (ETA) is to be used as the pH control agent. This proposed activity is being done as an Electric Power Research Institute (EPRI) Tailored Collaboration Project to evaluate actual plant performance of an alternate amine (pH control agent) in reducing corrosion product transport. Control of pH in the secondary cycle of pressurized water reactor plants is essential to minimize corrosion of secondary system components.

Safety Evaluation Summary

The use of pyrrolidine in the condensate/feedwater system and in the steam generators will enhance equipment integrity due to reduced corrosion rates at room temperature pH in these systems. It will not adversely affect any other secondary equipment. Since the use of pyrrolidine is expected to increase system pH, the elevated pH will reduce iodine volatility to some point less than presently evaluated, thus making the current FSAR Update evaluation more conservative.

No equipment is being installed or modified in the plant as a result of the use of pyrrolidine for pH control in the secondary system. Secondary water chemistry and/or the use of chemical additives or chemical controls for the secondary cycle is not addressed in the Technical Specifications. There is no reduction in the margin of safety as defined in the bases for any Technical Specification.

29. Chemistry Control Limits and Action Guidelines for the Secondary Systems
OP F-5:II, Rev. 15 (Units 1 & 2) (LBIE Log No. 97-056)

The procedure establishes the chemistry control limits for the condensate/feedwater and steam side of the plant. It identifies guidelines for corrective actions should limits be exceeded. This procedure revision introduces a new chemical to be used for scavenging oxygen from feedwater during system operation and from steam generator water when they are in wet lay-up during cold shutdowns. The new chemical, carbohydrazide (Nalco 1250+), supplements use of hydrazine as discussed in the procedure. Limits for its use and corrective action guidelines were provided.

Safety Evaluation Summary

This procedure revision involves a chemical that is in use at other oressurized water reactor power plants for the same functions as described above. The new chemical, carbohydrazide, was tested and evaluated to assure no material compatibility or chemical reaction issues that could contribute to corrosion that may increase the probability of or consequence of in a steam generator tube rupture, rupture of a main feedwater pipe, rupture of a main steam line or potential missiles from the main turbine.

The use of carbohydrazide, with respect to equipment important to safety, was determined to be bounded by the use of hydrazine, as described in the FSAR Update. There are no Technical Specifications associated with secondary chemistry control.

The use of carbohydrazide is not described in the National Pollutant Discharge Elimination System permit but since it is a less toxic chemical than hydrazine, as determined by testing, and non-hazardous, as identified per 29 CFR 1910.1200, prior approval was obtained from the California Regional Water Quality Control Board.

30. RHR Valves 8701/8702 Interlock Jumper Installation and Removal
MP I-38-M.1, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-046)

A procedure was written to install a jumper(s) for residual heat removal (RHR) when de-energizing the solid-state protection system (SSPS) output cabinet(s). The RHR suction valves interlock relays are powered from the SSPS output cabinets. To maintain the ability to open the RHR suction valve(s) when the SSPS output cabinet(s) are be de-energized, new Procedure MP I-38-M.1 will allow the installation of a jumper(s) to lock-in the RHR suction valve(s) open permissive. This defeats the "block opening" interlock. Jumper installation is limited to Mode 6 and defueled only.

When installing a jumper prior to de-energizing SSPS Train B with the RCS >390 psig or pressurizer vapor space >475ºF, the "block opening" interlock for Valve 8701 is defeated.

When installing jumper prior to de-energizing SSPS Train A with the RCS >390 psig, the "block opening" interlock for Valve 8702 is defeated.

Safety Evaluation Summary

This change only applies to Mode 6 with fuel removed from the reactor vessel. Therefore, because the RCS is depressurized, the change does not involve an unreviewed safety question.

31. OP J-2:I, “Main and Aux Transformer Return to Service”
OP J-2:1, Rev. 5 XPR (Unit 1) (LBIE Log No. 96-033)

This evaluation was written for an operating procedure that reflected the operation of DCPP Unit 1 without Auxiliary Transformer 1-1, which was destroyed during an attempt to energize it with a grounding device installed. The LBIE covered the change in plant configuration, as well as operation of the plant under such conditions. The plant configuration provided startup power to the units’ non-vital buses, allowing operation of the circulating water pumps and reactor coolant pumps continuously on the immediate-access offsite power source.

Safety Evaluation Summary

The evaluation documented that this configuration differed from that described in the FSAR Update, but that the consequences of a complete loss of flow (CLOF) event were not changed. Although the proposed configuration results in a slight increase in frequency of a CLOF event, it does not alter its classification as a Condition III event. An unreviewed safety question is not involved.

32. OP L-4, “Normal Operation at Power”
OP L-4, Rev. 38 (Unit 1) (LBIE Log No. 97-145)
OP L-4, Rev. 25 (Unit 2) (LBIE Log No. 97-146)

This procedure change was made to document a limitation described in FSAR Update Section 15.2.6.1. The limitation is adequately bounded by adding a restriction not to restart a reactor coolant pump while the reactor is critical.

Safety Evaluation Summary

Since the proposed change completely bounds and prevents violation of the FSAR Update-described limitation, the procedure does not involve a change to

the facility design, function, or method of performing the function as described in the FSAR Update. An unreviewed safety question is not involved.

33. Plant Cooldown from Minimum Load to Cold Shutdown
OP L-5, Rev. 41 (Unit 1) (LBIE Log No. 97-041)
OP L-5, Rev. 26 (Unit 2) (LBIE Log No. 97-040)

There was a discrepancy between FSAR Update Section 5.1.6.3 and OP L-5 regarding normal plant cooldown. The FSAR Update stated that steam was dumped to the main condenser. While true, steam is also dumped to the atmosphere via the 10 percent atmospheric dump valves during normal cooldown. An FSAR Update change was submitted to clarify use of the 10 percent steam dump valves.

Safety Evaluation Summary

The 10 percent atmospheric steam dump valves are normally used to control or reduce primary temperatures if the main condenser is not available. Use of the valves during normal cooldown, in the absence of any FSAR Update-analyzed accident or event, will not increase the probability of an accident or the probability of valve failure. Similarly, steam dump valve use during normal cooldown will not increase the consequences of an accident or create the possibility of a new accident or equipment malfunction. Technical Specification (TS) design margins are not affected by atmospheric dump valve use during normal cooldown.

34. Feed and Bleed of the CCW System
PEP M-246, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-182)

This procedure de-concentrates the component cooling water (CCW) system's exhausted chemicals by continuously adding makeup water to the surge line while draining CCW from the heat exchanger through temporary connections.

Safety Evaluation Summary

Even though this procedure places the CCWS in an unanalyzed configuration, the evaluation concludes that, there are adequate, dedicated personnel stationed to isolate the temporary connections and place the CCWS in a normal line-up in the event of abnormal indications. The evaluation indicates that the most likely problem encountered with this test is leakage due to failure of the temporary connections. The CCWS has, however, been analyzed in the FSAR Update for flooding near and leakage from the CCW heat exchangers.

35. Reactor Vessel Stud Tensioning
MP M-7.2, (Units 1 & 2) (LBIE Log No. 98-030)

The proposed change involved revising the reactor vessel stud tensioning and detensioning procedures to include new stud tensioning/detensioning sequences and corresponding tensioner pressures and revising the procedure to include a larger acceptable elongation tolerance range. As part of this optimized procedure, tensioning may be accomplished with the use of either six or three hydraulic tensioners, and may even be completed with only two tensioners in the event of a tensioner failure during the procedure.

Safety Evaluation Summary

The proposed procedure change involved no changes to the material of construction for configuration of the affected system (reactor vessel closure flange). The proposed change to the tensioning procedures has no possible impact on the analyzed fuel handling accidents. While the proposed procedure change does permit the reactor vessel studs to have a larger preload stress than has been previsouly permitted by the procedure, the closure flange and studs are demonstrated to meet acceptable ASME Code stress and fatigue limits, so there is no reduction in the margin of safety of any affected components.

36. Manual Installation of Steam Generator Nozzle Dams
MP M-7.61 (Units 1 & 2) (LBIE Log No. 97-062)

This procedure is for the inspection, installation, removal, and refurbishment of the steam generator primary nozzle dams. Use of the nozzle dams is necessary to permit performance of maintenance activities in the steam generator channel heads with the water level of the reactor coolant system (RCS) above the nozzles, such as during refueling operations. Additionally, the nozzle dams minimize the potential for the loss of foreign objects into the RCS piping from the steam generator channel head.

Safety Evaluation Summary

The design pressure of the nozzle dams exceeds both the normal and anticipated accident conditions. The seismic operating basis earthquake maximum load is less than the tested pressure of the nozzle dams. Precaution and limitation steps described in Operating Procedure A-2:III also help to ensure the design and tested loads are not exceeded. Based on the above, use of the nozzle dams have been evaluated and do not represent an unreviewed safety question, nor do they reduce the margin of safety as defined in the licensing documents.

37. Comparison of Final Feedwater Flow Nozzles to “AMAG”
PEP M-98A, Rev. 4 (Unit 2) (LBIE Log No. 97-178)

A cross-flow ultrasonic flow meter was installed on Unit 2 to replace the failed Controlatron system. The system is mounted externally to the final feedwater

header in the turbine building. Data are collected and then used to establish a correction factor for the operator heat balance, STP R-2B. This revision to the procedure relaxed the frequency of data collection and increased the data precision requirement since the plant process computer is the preferred data source.

Safety Evaluation Summary

The flow meter is used to set reactor power and, therefore, the calibration of the instrument remains safety related. Use of this procedure revision will not increase the uncertainty in reactor power above that required by Regulatory Guide 1.49. The externally mounted system will not breach any pipe should the hardware fail. In addition, reactor power will not change as a result of the system failing as there is a human/machine interface required to analyze the data before use.

38. Plant Demineralizer Media
CAP O-10, Rev. 1 (Units 1 & 2) (LBIE Log No. 98-008)

Use of up to 39 cubic feet of resin in any deborating demineralizer vessel (Units 1 and 2) is evaluated for the purpose of forced oxidation or deboration.

Safety Evaluation Summary

This change allows for an additional 9 cubic feet of resin to be loaded into a deborating demineralizer vessel for a total volume of 39 cubic feet. The additional volume will optimize cleanup and minimize radwaste during forced oxygenation of the reactor coolant system. The FSAR Update and Design Criteria Memorandum (DCM) describe the vessels as having a resin volume of 30 cubic feet. The vessel design drawing allows for a total of 39 cubic feet. The need to revise the FSAR Update and DCM to reflect the use of more than 30 cubic feet on resin in the deborating demineralizer vessels was addressed.

39. Notification of the Chemistry or Radiation Protection Sections
OP O-3, Rev. 19 (Units 1 & 2) (LBIE Log No. 97-130)

This procedure is part of the Chemistry Control Program. This revision adds a requirement that concurrence be obtained from Chemistry prior to using primary water in a nonradioactive system and specifically mentions use of primary water as makeup to the component cooling water (CCW) system. Section 9.2.2.3.3 of the FSAR Update states, “If the primary water makeup to CCWS valve is to be opened, the plant operator must obtain concurrence from the Chemistry and Radiation Protection Group.”

Safety Evaluation Summary

This procedure revision is an administrative change only for the purpose of bringing this procedure into agreement with the FSAR Update. The increase in administrative control does not increase the probability of an accident or the consequences of an accident. Therefore, there is no adverse impact on current plant safety.

40. Control of Flammable and Combustible Materials
OM8.ID4, Rev. 5 (Units 1 & 2) (LBIE Log No. 97-126)

This procedure revision clarifies the controls required for combustible materials when introduced into the plant and the amount that may be introduced without being regarded as "bulk storage."

Safety Evaluation Summary

The guidance provided by this revision ensures the introduction of combustible materials will not impact DCPP's ability to achieve and maintain safe shutdown as described in the FSAR Update. There are no adverse consequences due to this revision.

41. General Authorities and Responsibilities of Operating Personnel
OP1.DC10, Rev. 4 (Units 1 & 2) (LBIE Log No. 97-118)

This procedure change added the Work Control Shift Foreman (SFM) position and related responsibilities to the shift operating personnel. FSAR Update Section 13.1.2.2.2.4 describes the shift operating personnel, including the Unit Shift Foreman. A "Work Control" Shift Foreman position was being implemented to perform some of the administrative functions of the SFM. Since an FSAR Update change was being made to support this change, a safety evaluation was performed.

Safety Evaluation Summary

Since there is no change being proposed for the duties and responsibilities of the Unit Shift Foreman (SFM) (as described in the FSAR Update), and since adding a Work Control SFM will serve to enhance the crew's ability to respond to an emergency, the proposed change will not increase the probability or consequences of an accident previously described in the FSAR Update. An unreviewed safety question is not involved.

42. Revision to Plant Administrative Procedure on the Authorities and Responsibilities of Operating Personnel
DLAP OP1.DC10, Rev. 3 (Units 1 & 2) (LBIE Log No. 96-043)

This Operations Department Administrative Procedure establishes authorities and responsibilities of plant Operators, Shift Supervisors, Shift foremen, and Shift Technical Advisors in terms of procedure usage, response to instrumentation, actions in emergencies, and other related matters.

Safety Evaluation Summary

This procedure was revised to allow the unit Shift Foreman to delegate some administrative duties to permit better control room supervision. FSAR Update Section 13.1.2.2.2.4 describes the Shift Foreman's responsibilities.

43. Control of Plant Equipment Not Required by the Technical Specifications
OP1.DC16, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-102)

In letter DCL-95-222, dated October 4, 1995, PG&E submitted License Amendment Request (LAR) 97-07 that proposed to relocate several Technical Specifications (TSs) to Equipment Control Guidelines (ECGs) and to reference the ECGs in the FSAR Update. During review of LAR 97-05, the NRC staff requested PG&E to add the following wording to FSAR Update Section 16.1: "ECGs containing relocated TSs are incorporated into the FSAR Update, by reference, in Table 16.1-1. For ECGs listed in Table 16.1-1, if the equipment cannot be returned to service as required by the ECG, then a review in accordance with 10 CFR 50.59 is required."

PG&E made these changes to the FSAR Update, and incorporated them into plant procedures by revising OP1.DC16, Section 5.5, "Noncompliance with Equipment Control Guidelines," to add:

Attachment 7.2, "Equipment Control Guidelines - Technical Specifications Relocated in Accordance With NRC's Final Policy Statement on Technical Specification Improvements." The ECGs listed in Attachment 7.2 are the same ECGs listed in FSAR Update Table 16.1-1.

A requirement that if an ECG listed in Attachment 7.2 is not complied with, then prior to exceeding the completion time of any required action, a 10 CFR 50.59 evaluation must be approved by the PSRC justifying the acceptability of exceeding the completion time.

Safety Evaluation Summary

The revision to OP1.DC16 places increased administrative controls on ECGs that are relocated from TSs, but does not change the ECG requirements themselves.

44. Setting of the Centrifugal Charging Pump 2-1 Miniflow Orifice Flow Rate
PROC PEP M-223 (Units 1 & 2) (LBIE Log No. 96-046)

Erosion of the centrifugal charging pump (CCP) 2-1 recirculation line restricting orifice resulted in increased flow as measured at power. This procedure measures the flow through the CCP 2-1 recirculation orifice during the CCP full flow performance test in Mode 6. The as-found flow is throttled using a manual valve downstream of the orifice to ensure that CCP 2-1 recirculation orifice design resistance is restored, and to ensure that CCP 2-1 will pass emergency core cooling system (ECCS) flow balance (STP V-15) acceptance criteria. Throttling of the manual valve is not the designed method of preventing excess recirculation flow; therefore, PEP M-223 results in a change to the method of performing the CCP recirculation flow limiting function as described in the FSAR Update.

Safety Evaluation Summary

Throttling the manual valve in the CCP recirculation line to lower recirculation flow will prevent the CCP from exceeding the allowable total pump flow while maintaining the required pump minimum flow. Although the manual valve's design function is to isolate the recirculation line, it will perform as a throttle valve. Restoring the recirculation line design flow resistance will ensure that CCP 2-1 is available to perform its accident mitigation function, and thus maintain the ECCS flow balance.

45. Control Room Vent
AR PK15-06, Rev. 14 (Unit 1) (LBIE Log No. 97-143)

This procedure revision addressed the response to losing both subtrains of control room ventilation system (CRVS) cooling, as described in the FSAR Update. Previously, there was no guidance provided for this event, since there are four equally redundant subtrains available to perform CRVS functions. However, to prevent the possibility of overlooking the FSAR Update described response, these actions were added to the procedure.

Safety Evaluation Summary

Since the proposed procedure revision adds the detail as described in the FSAR Update, there is no change to the facility or operation as described in the FSAR Update. The safety evaluation was performed since the FSAR Update describes response to loss of all CRVS in moderate detail. An unreviewed safety question is not involved.

46. Routine Surveillance Test of PDP 2-3
STP P-PDP-23, Rev. 5 (Units 1 & 2) (LBIE Log No. 97-209)

Operator actions to secure the positive displacement pump (PDP) upon safety injection (SI) actuation were added to allow the surveillance test procedure (STP) to be run with a potential nonconforming condition found in the inadvertent safety injection analysis assumptions.

Safety Evaluation Summary

The procedure revision allowed the PDP to be run with added compensatory measures to mitigate a nonconservative error found in the inadvertent SI analysis. Dedicated operators were required to be stationed in the control room and at the breaker cubical to secure the PDP upon a SI actuation. The inadvertent SI analysis has time critical operator actions in emergency operating procedures (EOPs) to ensure that the pressurizer safety valves will operate within their design and licensing basis. The safety evaluation was required to be performed in accordance with Generic Letter 91-18, Revision 1, which requires a 50.59 review to be performed for any interim compensatory action taken to address a degraded or nonconforming condition. Operator actions were analyzed, in accordance with Information Notice 97-78, to ensure that the actions were adequate to maintain the reactor coolant system within the limits to equipment. The operator actions were determined to be within the training and capability of the operators, and the time allowed in the analysis, and not to affect the performance of operator actions required for EOPs. Potential misoperations were analyzed and determined not to affect plant response to other transients.

47. Environmental Radiological Monitoring Procedure
RP1.ID11, Rev. 33 (Units 1 & 2) (LBIE Log No. 97-193)

In response to a finding from Nuclear Quality Services Audit 962610007, this procedure was revised to include training of personnel responsible for quality-related Radiological Environmental Monitoring Program (REMP) activities, allow the sampling frequencies specified in Table 1 to be extended by 25 percent, and include how training of REMP personnel is to be documented.

Safety Evaluation Summary

The proposed changes to the FSAR Update only involve analysis of environmental samples for the REMP, or editorial changes that do not impact the intent of the FSAR Update. These changes are not accident related, and they do not affect accident analysis or safety-related equipment.

48. Spent Fuel Cooling System
DCM S-13, Rev. 3.2 (LBIE Log No. 96-045)

One sentence in the Design Criteria Memorandum (DCM) was replaced with a paragraph that added clarification and updated detail about the pool water design temperatures assumed in the spent fuel cooling system criticality

analysis. A design memo was referenced that showed that spent fuel pool temperatures could drop to as low as 32°F, well below the minimum ultimate heat sink of the plant. Previously, 68°F was considered the design basis.

Safety Evaluation Summary

A decrease in spent fuel pool temperature has no contribution to the FSAR Update accidents assumed for the spent fuel pool. The contribution to the consequences of an accident is not increased because the resultant K_{eff} remains below the Technical Specification limit of 0.95.

D. Tests and Experiments

1. Continued Operation in Mode 3 with MSSV Inoperable
(Units 1 & 2) (LBIE Log No. 96-028)

This safety evaluation was in response to the August 10, 1996, DCPP unit trips in which main steam safety valves (MSSVs) lifted well beneath set pressure. The safety evaluation covered (in advance) the period of time during which six inoperable MSSVs were tested and reset while the units were in Mode 3. The assumption was that, should a high pressure transient occur during this period, the MSSVs would operate at a lower pressure than set pressure. This was a change in the performance of the MSSVs from that described in the FSAR Update. It was also a condition that might affect safe operation of the plant but was not anticipated or evaluated in the FSAR Update. The safety evaluation also supported a prompt operability assessment.

Safety Evaluation Summary

A lower MSSV opening pressure is a benefit for all FSAR Update accident analyses associated with overpressure protection or minimum heat removal. A review of the accident analysis profile shows that the only FSAR Update accident analyses potentially negatively impacted by the lower pressure are those associated with steam generator tube rupture (SGTR) or overcooling. In the case of SGTR, it was shown that the various effects of Mode 3 operation compared to Mode 1 caused a large enough benefit in SGTR dose and overfill calculations to offset the negative effects of a lower than anticipated lift pressure. In terms of overcooling, the low opening pressure of the MSSVs were bounded by steamline break analyses from a shutdown condition.

2. RCS Flow Calorimetric Beginning of Cycle to End of Cycle
(Units 1 & 2) (LBIE Log No. 97-003)

This procedure describes the performance of a primary to secondary calorimetric and determines the corresponding reactor coolant flowrate. This safety analysis covers the performance of this test at the end of cycle (EOC) operation versus the beginning of cycle (BOC) operation. This was generated as a non-conformance corrective action to document previous EOC testing, and does not describe the current practice of testing at BOC.

Safety Evaluation Summary

The performance of Surveillance Test Procedure (STP) R-26 was moved to EOC to reduce the bias effect of hot leg streaming on the RCS flow measurement. The movement of the STP to EOC and the consequent verification of flow at the beginning of the next cycle using plant indication resulted in larger flow measurement random error and larger RCS loss of flow-low setpoint random

error. The larger errors were determined by calculation and have been addressed in STP R-26 by the application of a flow penalty,which is used to bias the RCS measured flow in the conservative direction. This safety evaluation determined that there is no adverse effect on the DCPP LOCA and non-LOCA safety analyses as a consequence of the flow penalty method. In addition, the RCS flow elbow taps are documented to be reliable for the verification of RCS flow after restart from refueling.

The performance of STP R-26 at EOC provided the requisite level of safety and protection as prescribe in the Technical Specifications.

3. Inservice Testing (IST) Program Plan (Plan) 2nd 10-Year Interval, Revision 12 (Units 1 & 2) (LBIE Log No. 97-050)

This revision included the following changes:

- Removed manual stroke test of RHR-8701 and -8702 from the Inservice Test (IST) Plan P
- Removed several component cooling water (CCW) Header “C” relief valves from IST Plan P
- Removed partial stroke test requirement for emergency core cooling system (ECCS) check valves from IST Plan P

Safety Evaluation Summary

The revision deleted manual stroke test of the residual heat removal (RHR) suction from the reactor coolant system (RCS) hot leg valves RHR-8701 and -8702. Manual operation of these valves is not required because accidents analyzed in the FSAR Update would make the containment building inaccessible and therefore these valves could not be operated post accident.

Several CCW Header ‘C’ relief valves were deleted from the IST Plan P. These valves do not protect vital components, and they only function as relief valves when the subsystem being protected is out of service.

The revision also included removal of the partial stroke test after disassembly requirement from the IST Plan P for several ECCS check valves. NUREG-1482 recommends the partial stroke if practical. The evaluation shows that removal of these items does not create an unreviewed safety question.

4. Containment Fan Cooler Unit (CFCU) Time Delay Relays Replacement Test Preventive Mainteance Testing (PMT) 23.24-23.28 (Unit 2) (LBIE Log No. 97-129)

This item is related to Design Change Package (DCP) E-50344, which replaces the Unit 2 containment fan cooler units (CFCU) time delay timers with more accurate digital type Agastat DSC timers. This evaluation was performed to support the performance of this PMT with the plant in Mode 1.

Safety Evaluation Summary

Testing of the CFCU from the solid-state protection system (SSPS) using a slave relay is not described in the FSAR Update. Also, testing of the CFCU using a simulated auto-transfer signal is not described in the FSAR Update. Connecting the toggle switch across the slave relay contacts does not prevent normal operation of the SSPS slave relay or the auto-transfer relay. Because no engineered safety feature components are disabled during the performance of this test, there is no adverse effect on safety.

5. Commitment Change - Revision of Corrective Action Regarding Main Steam Safety Valve Testing for Notice of Deviation (Inspection Report Nos. 50-275/96-12; 50-323/96-12)
Letter DCL-97-073 (Units 1 & 2) (LBIE Log No. 97-075)

PG&E eliminated an NRC commitment on main steam safety valve (MSSV) testing.In a Safety Evaluation Report dated December 26, 1995, the NRC referenced PG&E's letter of November 1, 1995, in which PG&E described an augmented testing program for the main steam safety valves (MSSVs). PG&E stated in the letter that during the seventh refueling outages for Units 1 and 2, PG&E would obtain valve signature profiles on live steam and with the AVK test equipment. PG&E would also obtain the magnitudes of the AVK test equipment bias. PG&E's intent in collecting this data was to develop valve-specific correction factors (more recently called valve-specific mean seat areas, or MSAs) which would be used to increase the accuracy of setpoint adjustment during MSSV testing. The data to be collected and the derivation of valve specific MSAs for subsequent use in setting MSSVs would be used to establish a means for administrative control over the testing and accurate setting of MSSVs.

The commitment was eliminated because PG&E discontinued the use of the AVK test equipment and methodology (TE&M) in favor of Trevitest TE&M.

Safety Evaluation Summary

The collection of data would have been for the development of valve-specific MSAs for use with AVK TE&M. As the use of valve-specific MSAs with the AVK equipment had demonstrated the inability to assure setting of MSSVs within their Technical Specification limits, the data would not be obtained. The Trevitest equipment and the Trevitest standard MSA had been demonstrated throughout the industry to provide more accurate valve settings. Thus, the Trevitest equipment was selected for use during future MSSV testing rather than AVK.

Therefore, testing and resetting of MSSVs with setpoints meeting the Technical Specification limits did not constitute an unreviewed safety question.

6. Auxiliary Saltwater (ASW) Flow Test Procedure
Surveillance Test Procedure (STP) M-26, Rev. 21 (Unit 1) (LBIE Log No. 97-195)
STP M-26, Rev. 2 (Unit 2) (LBIE Log No. 97-196)

This procedure change revised the frequency of flow testing of the ASW system from monthly to quarterly. This was a change to the frequency as stated in PG&E's responses to Generic Letters 89-13 and 91-13.

Safety Evaluation Summary

The implementation of equipment control guideline (ECG) 17.2 for continuous chlorination, operating experience and inspection results demonstrate that the ASW system is not susceptible to flow degradation due to biofouling, siltation, or coating failure over a quarterly inspection interval.

Continuous chlorination has eliminated growth of biofouling organisms in the ASW system. The design and operation of the ASW system prevent siltation of out of service or inservice piping. Inspection of the ASW pipe and heat exchangers has demonstrated that there is no degradation of the pipe liner material that could block flow.

Based on the above, the increase in the surveillance interval will not create an unreviewed safety question.

7. 4-kV Vital Bus Undervoltage Relay Calibration
Surveillance Test Procedure (STP) M-75, Rev. 18 (Units 1 & 2) (LBIE Log No. 97-165)

Prior to Revision 18, STP M-75 was performed on a deenergized bus with the plant in Mode 5 or 6. Revision 18 provides the necessary precautions and instructions for performing undervoltage relay calibration with the bus energized and the plant in Mode 1. These changes cause the associated diesel generator and bus auxiliary transformer or startup transformer feeders to be inoperable at various times during the test. With extended fuel cycles, this change was necessary to comply with the 18-month calibration frequency required by Technical Specification Table 4.3-2, items 7a and 7b.

Safety Evaluation Summary

Performance of STP M-75 in Mode 1 is an abnormal condition compared to past practice and therefore represents a new plant configuration. Performance of STP M-75 in Mode 1 does not make the 4-kV bus inoperable. Periods of inoperability for the diesel generator and auxiliary or startup feeders are within

the time constraints of Technical Specification action statements. Therefore, Technical Specification requirements and margins of safety are maintained. Performance of the test will not initiate any accidents or plant transients. All FSAR Update Chapter 15 accidents have been evaluated for occurrence with minimum safeguards equipment available. Therefore, there is no unreviewed safety question.

8. Main Steam Safety Valve Testing (STP M-77B)
STP M-77B, (Units 1 & 2) (LBIE Log No. 97-119)

Main steam safety valve (MSSV) discs were replaced with an improved material (Inconel X-750). This necessitated a change to the test procedures allowing the elimination of Mode 1 testing (20 to 30 days after an outage). The testing ensured no sticking following restart with the 422SS MSSV discs. A new STP (STP M-77B) was developed to document the Inconel X-750 test and validation plan and was also designed to minimize test cycling of the valves.

Safety Evaluation Summary

The new material with pre-oxidizing reduces the galling potential and therefore ultimately the sticking of the disc and nozzle within the MSSV. The test plan is an iterative process that ensures continuous valve performance. The reduction of testing and valve cycles serves to improve overall valve performance. Based on these considerations, the probability or consequence of accidents is not affected. Additionally, the improved performance and reduced maintenance cycling reduce the probability and consequence of an equipment failure. The alteration of the disc material and reduction of testing does not introduce new accidents.

9. Boric Acid Inventory
STP R-20, Rev. 18 (Units 1 & 2) (LBIE Log No. 97-194)

This change involved a procedure revision to Surveillance Test Procedure R-20 to implement Plant Staff Review Committee (PSRC) Technical Specification Interpretation 97-05, which increased the minimum refueling water storage tank (RWST) level from 400,000 gal. to 443,455 gal. Also the level indicator reading error penalty was lowered from 5 percent to 2 percent.

Safety Evaluation Summary

PSRC Technical Specification Interpretation 97-05 increases the minimum RWST level to 443,455 gal. This required level increase is due to revisions to the containment recirculation sump level calculations. The level indication post-accident monitoring (PAM) calculation lowered the error penalty from 5 percent to 2 percent for RWST level switches.

10. Plant Process Computer and Manual Operator Heat Balance
Surveillance Test Procedure (STP) R-2B1, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-065)
STP R-2B1, Rev. 1 (Unit 2) (LBIE Log No. 97-066)

The proposed activity is to change the standard test procedure requirement to a check, and reset if required, of the nozzle fouling factor (NFF) for curtailments below 85 percent power. The newly proposed check determines if the existing NFF may continue to be used for the return to 100 percent power. Should the NFF not meet certain criteria, it shall be reset to unity before proceeding to 100 percent power and a new NFF will need to be calculated.

Safety Evaluation Summary

The procedural change for re-establishing or verifying the validity of the NFF does not increase the probability, or change any of the consequences, of an accident previously analyzed in the FSAR Update. This verification of the NFF only aids in assuring that the reactor is operating at the allowable thermal output as licensed.

11. Containment Fan Cooler Unit (CFCU) Timers Setting Verification
TP TB-9627, Rev. 0 (Units 1 & 2) (LBIE Log No. 96-041)

Testing of the containment fan cooler unit (CFCU) from the solid-state protection system (SSPS) using a “simulated” slave relay contact is not described in the FSAR Update. This test procedure describes use of a toggle switch for this test.

Safety Evaluation Summary

Using a simulated signal to start only the CFCU instead of the slave relay requires less equipment to be removed from service to perform this test. All ESF equipment remains in service to mitigate an accident. No engineered safety feature component is disabled for the performance of this test, so there is no increase in the probability of an accident. Therefore, an unreviewed safety question is not involved, and a change to the DCPP Technical specifications is not involved.

12. Component Cooling Water (CCW) to Spent Fuel Pool Heat Exchanger Flow Test
TP TB-9703, Rev. 0 (Unit 1) (LBIE Log No. 97-061)

The purpose of this test is to provide data to evaluate the desirability of proposed future modifications that would increase the heat transfer capacity of the existing spent fuel pool heat exchanger. The test involves increasing the CCW flow from a design flow rate of 3000 gpm to approximately 5000 gpm for no more than five minutes.

Safety Evaluation Summary

This test will not impact the ability to remove decay heat from the reactor core or the spent fuel pool. The test can not impact the operation of the CCW system to any significant extent, nor can it impact the reactivity controls and shutdown margin. No physical modifications will be made to the plant and the design and/or function of the system has not been changed. Based on the above, there is no unreviewed safety question.

13. Cable Spreading Room Pressure Boundary Integrity Verification
TP TB-9711, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-142)

Test Procedure (TP) TB-9711 involves a pressure test on the cable spreading room boundary to determine the amount of leakage present. This test consists of isolating the heating, ventilating, and air conditioning (HVAC) to the room to simulate the conditions present during a CO_2 discharge, and then pressurizing the room to 0.04 in. - 0.06 in. water and cooling by using a fan. The amount of air leaking out of the room will be determined by the installed test equipment.

Safety Evaluation Summary

Isolating the room HVAC will result in a modest rise in ambient temperature above the initial ambient temperature of 80°F. Test conditions require that the cable spreading room be maintained below a maximum limit of 108°F. This temperature limit was conservatively chosen based upon the 120°F operating limit for the Eagle-21 system. Additionally, the maximum allowed test temperature is well below the operating limit of the reactor protection system and electrical equipment in the room. Equipment Control Guideline 23.1 limits the temperature in the cable spreading room to 119°F. In order to maintain the control room habitable during a postulated accident, the test procedure contains instructions to terminate the test in the event of an accident, and to open a door to relieve the pressure. At all times the control room pressurization system will be capable of maintaining a pressure higher than the pressure in the cable spreading room, which will ensure that any leakage is to the outside of the control room.

14. Motor-Operated Valve (MOV) Flow Test - Charging Injection Valves in Mode 5
TP TB-98-2, Rev. 0 (Unit 2) (LBIE Log No. 98-031)

Surveillance Test Procedure (STP) V-15 (ECCS Flow Balance Test) is currently performed in Mode 6 with the reactor vessel head removed. Although dynamic testing of the charging injection Motor Operated Valves (MOVs) 8801A/B & 8803A/B has been previously performed at DCPP, it has been done in Mode 6

under the STP V-15 test conditions. This procedure is written to perform dynamic testing of the valves in Mode 5.

Safety Evaluation Summary

The valves being tested are designed to operate under the conditions established for the test. The charging system is operated within its design parameters during the test, as are the individual components within the system. No material changes are made to the system or components being tested. Low temperature overpressure protection is enabled during testing to address potential overpressurization. Residual heat removal (RHR) system operation is consistent with current Mode 5 or 6 operation of the system. By using the operable centrifugal charging pump , the required boration flowpath is maintained throughout the test. RHR flow continues to provide reactor coolant system cooling during the test.

Since no material changes are made to the system, and system and component operation is within design parameters and Technical Specification limitations, the test does not involve an unreviewed safety question.

E. Equipment Control Guidelines

1. Administrative Changes to ECGs
   ECG 0.0, Rev. 3 (LBIE Log No. 97-103)
   ECG 7.7, Rev. 1 (LBIE Log No. No. 97-109)
   ECG 17.3, Rev. 1 (LBIE Log No. No. 97-110)
   ECG 23.1, Rev. 1 (LBIE Log No. 97-111)
   ECG 39.6, Rev. 1 (LBIE Log No. 97-112)
   ECG 99.9, Rev. 1 (LBIE Log No. 97-113)
   ECG 4.3, Rev. 1 (LBIE Log No. 97-104)
   ECG 7.3, Rev. 2 (LBIE Log No. 97-105)
   ECG 7.4, Rev. 1 (LBIE Log No. 97-106)

   In PG&E's Letter DCL-95-222, dated October 4, 1995, PG&E submitted License Amendment Request (LAR) 97-07 that proposed to relocate several Technical Specifications (TSs) to Equipment Control Guidelines (ECGs) and to reference the ECGs in the FSAR Update. During review of LAR 97-05, the NRC staff requested PG&E to add the following wording to FSAR Update Section 16.1: "ECGs containing relocated TSs are incorporated into the FSAR Update, by reference, in Table 16.1-1. For ECGs listed in Table 16.1-1, if the equipment cannot be returned to service as required by the ECG, then a review in accordance with 10 CFR 50.59 is required."

   PG&E made these changes to the FSAR Update, and incorporated them into the existing ECGs listed in FSAR Update Table 16.1-1 by adding the following note to each ECG: "Prior to exceeding the Completion Time of any Required Action, a 10 CFR 50.59 evaluation must be approved by the PSRC justifying the acceptability of exceeding the Completion Time."

   Safety Evaluation Summary

   The revision to ECGs relocated from TSs places increased administrative controls on obtaining approval to exceed completion times for required actions but does not change the ECG requirements themselves. By requiring Plant Staff Review Committee approval of a 10 CFR 50.59 safety evaluation for an extension of a completion time for a required action, assurance is provided that the extension will not involve an unreviewed safety question.

2. Equipment Control Guidelines Applicability
   ECG 0.0 & 0.0, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-029)

   This issue concerns opposite wording between Equipment Control Guidelines (ECG) 0.4 and Technical Specification (TS) 3.0.4 regarding allowance of mode transitions. The less restrictive wording of ECG 0.4 could have permitted mode transitions which would not have been permitted under the more restrictive wording of TS 3.0.4. However, a review identified no actual instances where the

plant has been in an ECG shutdown action statement. The ECG 0.4 wording problem will be corrected by a revision to the ECG.

Safety Evaluation Summary

Because this change is a revision to an ECG, Procedure OP1.DC16 requires a 50.59 safety evaluation. The ECG revision involved revising ECG 0.4 to more restrictive language regarding allowance of mode transitions to agree with TS 3.0.4. The probabilities of occurrence of an accident or consequences are not increased. The probability of occurrence of a malfunction of equipment important to safety previously evaluated is not increased. A new type of accident is not created. The margin of safety as defined in the Technical Specifications is not reduced.

3. Post Accident Sampling System
ECG 11.1, Rev. 5 (Unit 1) (LBIE Log No. 97-004)

This Equipment Control Guideline (ECG) revision changes the Mode Applicability requirements for monitoring reactor coolant for dissolved hydrogen from "with fuel in containment" to "Modes 1 through 4." In addition, this revision clarifies the Technical Specification bases to reference the Unit 1 PG&E letter to NRC and reference Surveillance Test Procedure (STP) G-14, Rev. 1, as the original acceptance criteria document for post-accident sampling.

Safety Evaluation Summary

This ECG revision is an administrative change only, and does not involve any physical changes to the post-accident sampling system (PASS) or dissolved hydrogen monitors. It only affects the mode applicability requirements of a plant monitoring instrument. The dissolved hydrogen monitors will continue to function post-loss-of-coolant accident in accordance with NUREG-0737 and Regulatory Guide 1.97 when indication of dissolved hydrogen content in the reactor coolant system (RCS) is required for accident monitoring purposes.

The capability to obtain and analyze RCS samples under accident conditions will be maintained as a result of this ECG revision. This change does not affect the operation of any safety-related systems or equipment and does not introduce any new failure modes for any equipment in the PASS or any safety-related system component or equipment. This change does not affect Technical Specification 6.8.4.e, "Post accident Sampling." Therefore, there is no reduction in the margin of safety.

4. Post Accident Sampling System
ECG 11.1, Rev. 6 (Units 1 & 2) (LBIE Log No. 97-170)

The revision to Equipment Control Guideline (ECG) 11.1 added a note to the actions to include the reporting requirement in Facility Operating License DPR-80, Section 2.G. In accordance with the provisions of 10 CFR 50.72, the NRC must be notified within 24 hours when the post accident sampling system and its alternate sampling methods are not available, with written follow-up in accordance with the provisions of 10 CFR 50.73.

Safety Evaluation Summary

A safety evaluation was performed because revision of an ECG requires a safety evaluation. This revision is an administrative change to make the reporting requirement more visible to the Operations staff. The reporting requirement was removed from Surveillance Test Procedure G-4 and placed in ECG 11.1 and Procedure XI1.ID2.

5. Equipment Control Guideline: CCW Surge Tank Pressurization System
ECG 14.1, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-074)

ECG 14.1 was developed and implemented in 1996 to place administrative controls on the newly installed component cooling water (CCW) surge tank pressurization system. In 1997, PG&E elected to convert the ECG to a technical specification and submitted License Amendment Request (LAR) 97-05 to accomplish this (Reference DCL-97-074, dated May 22, 1997). In developing the LAR, a more conservative allowed outage time (AOT) was defined, and an additional surveillance requirement was identified. Revision 2 to ECG 14.1 was issued to have the ECG requirements coincide with the proposed LAR.

Safety Evaluation Summary

Revisions 0 and 1 to ECG 14.1 were approved to establish controls to assure that the CCW pressurization system and the CCW system are capable of performing their required functions. Revision 2 to ECG 14.1 reduces the AOT for the surge tank pressurization system from 7 days to 12 hours based on a probabilistic risk assessment. The CCW pressurization system is designed to mitigate an accident and is not an accident initiator. ECG 14.1 establishes administrative requirements and the proposed changes, including the reduction in the AOT, will not affect the method of operation of the CCW system or the method by which the CCW system performs its function.

6. Fire Suppression Systems/Fire Suppression Water Systems
ECG 18.1, Rev. 4 (Units 1 & 2) (LBIE Log No. 97-199)

This Equipment Control Guideline (ECG) revision extends the urveillance frequency for testing fire suppression valves as specified in the ECG Surveillance Requirement 18.1.8 (valves not testable during plant operation) from 18 months to 24 months to be consistent with 24-month fuel cycles.

Safety Evaluation Summary

This change does not alter the way any important to safety structure, system, or component functions, and does not change the manner in which the plant is operated. Increasing the surveillance interval of the fire water valves not testable during plant operation will not alter the operation of the fire water system or the intent or method by which the surveillance is presently conducted. The operability of the fire water valves is not affected by the surveillance interval change as these valves are maintained in the sealed open position to ensure a water source is always available.

This change does not result in a physical modification to either the valves or any important-to-safety system, structure, or component. The fire water valves and fire water system are not addressed in any Technical Specifications or associated with any margin of safety. Since the increased surveillance frequency does not impact the operation of the fire water system, this change does not involve a reduction in margin of safety as defined in the Technical Specifications.

7. Fire Hose Stations
ECG 18.2, Rev. 5 (Units 1 & 2) (LBIE Log No. 97-200)

Revision to Equipment Control Guideline (ECG) 18.2 changes the surveillance requirement frequency of fire hose inspections for hose stations not accessible during plant operation from 18 months to at least once per refueling interval (24 months).

Safety Evaluation Summary

With the inspection interval extended 6 months, the hoses and valves remain qualified to perform their intended functions. As a result, inadvertent introduction of fire water into containment is not considered a credible event due to hose aging and subsequent failure.

8. Fire Hose Stations
ECG 18.2, Rev. 4 (Units 1 & 2) (LBIE Log No. 97-173)

Equipment Control Guideline (ECG) 18.2 Surveillance Requirement 18.2.6 required that hose hydrostatic tests be conducted every 3 years at a pressure of 150 psig or at least 50 psig above the maximum fire main operating pressure, whichever is greater. This change would revise the hydrostatic test pressures to conform with the requirements of National Fire Protection Association (NFPA) Standard 1962, "Care, Use and Service Testing of Fire Hose Including Couplings and Nozzles." NFPA 1962 requires that the hoses be tested to 150 psig, consistent with the current requirements.

Safety Evaluation Summary

Fire hoses are not accident initiators, therefore the probabilities of occurrence and the consequences of an accident are not increased. The design of any equipment important to safety, the method by which any equipment important to safety performs its required function, and the operation of equipment important to safety are not affected. Therefore, no accident consequences are increased, no new accidents are created, no new types of equipment malfunctions created and there is no reduction in the margin of safety as defined in the basis for any Technical Specifications.

9. Fire Hose Stations
ECG 18.2, Rev. 3 (Units 1 & 2) (LBIE Log No. 96-007)

The revision to Equipment Control Guideline (ECG) 18.2 on Fire Hose Stations added operability requirements for two existing fire hose stations located in the intake structure. The fire hose stations are now credited as part of the fire protection for 10 CFR 50, Appendix R circuits to the auxiliary saltwater pumps.

Safety Evaluation Summary

The revisions made to the ECG provide guidance in controlling the operation of the fire hose stations located in the intake structure. Accidents analyzed in the FSAR Update are unaffected and operability of equipment important to safety is not impacted. Therefore, the change does not involve an unreviewed safety question.

10. Fire Detection Systems
ECG 18.3, Rev. 3 (Units 1 & 2) (LBIE Log No. 96-008)

This revision to Equipment Control Guideline (ECG) 18.3 on Fire Detection Systems changed a note regarding the heat sensors that actuate the carbon dioxide flooding systems in the intake structure. The note changed a reference to a new section that was added to ECG 18.5 (CO_2 Systems). The CO_2 System and its heat sensor are now credited as part of the fire protection for 10 CFR 50. Appendix R circuits to the auxiliary saltwater pumps.

Safety Evaluation Summary

The changes made to the ECG provide administrative controls for fire protection features credited to protect one train of redundant safe shutdown circuits. By including these fire protection features into ECGs, adequate compensatory measures are provided should these systems be impaired. The addition of fire suppression and detection systems into existing ECGs does not affect the function of equipment important to safety. By including these fire protection features into the ECGs, stricter surveillance requirements are implemented and compensatory measures are implemented should these systems become impaired. Based on the above criteria and justification, an unreviewed safety question is not involved.

11. Spray and/or Sprinkler Systems
ECG 18.4, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-192)

This Equipment Control Guideline (ECG) deletes ECG Surveillance Requirement (SR) 18.4.5. The current requirements specify cycling each valve in the flow path that is not testable during plant operation. The only plant valves in these systems that fall into this category are located inside the containment. These valves are already covered by ECG 18.1.8. Thus ECG 18.4.5 is a duplicate and is not required.

Safety Evaluation Summary

This change does not affect the way any important to safety structure, system, or component functions, nor does it change the manner in which the plant is operated. The elimination of the surveillance requirement of ECG 18.4.5 for the fire water valves does not have any impact on plant equipment because it is a duplicate of the requirements of ECG 18.1.8. The operability of the fire water valves is not affected by eliminating this surveillance requirement because the only valves not testable during plant operation are located inside the containment and are covered by ECG 18.1.8.

The fire water valves and fire water system are not addressed in any Technical Specification or associated with any margin of safety. This change does not impact the operation of the fire water system or the fire water valves. Therefore, it does not involve a reduction in the margin of safety as defined in the Technical Specifications.

12. CO_2 Systems
ECG 18.5, Rev. 3 (Units 1 & 2) (LBIE Log No. 97-201)

This Equipment Control Guideline (ECG) revision extends the frequency for ECG Surveillance Requirement (SR) 18.5.2.5 from 18 months to at least once per refueling interval (24 months). Performance of this SR during refueling outages is specified due to the personnel safety associated with entering the circulating water pump (CWP) motor cubicle to perform this SR during power operation.

Safety Evaluation Summary

The high pressure CO_2 system is designed to mitigate a fire and is not an accident initiator. The system is provided to suppress oil fires internal to the CWP motor housing. This change does not alter the way any important-to-safety structure, system, or component functions, nor does it change the manner in which the plant is operated. Increasing the surveillance interval for the high pressure CO_2 detection system does not result in any physical modifications to either the detection system or any important to safety structure, system, or component. This change does not alter the intent or method by which the surveillance is presently conducted.

The high pressure CO_2 detection system is not addressed in any Technical Specification or associated with any margin of safety. The increased surveillance frequency does not impact the operation of the detection or suppression system. Therefore, this change does not involve a reduction in margin of safety as defined in the basis for any Technical Specification.

13. CO_2 Systems
ECG 18.5, Rev. 2 (Units 1 & 2) (LBIE Log No. 96-009)

This revision Equipment Control Guideline (ECG) 18.5 on carbon dioxide systems added operability requirements for the high pressure CO_2 system at the intake structure. The CO_2 System is now credited as part of the fire protection for 10 CFR 50, Appendix R circuits to the auxiliary saltwater pumps.

Safety Evaluation Summary

The high pressure CO_2 system in the intake structure is credited to suppress the combustible materials located in the circulating water pump (CWP) motor housings. This suppression system protects at least one train of auxiliary saltwater (ASW) pump and exhaust fan circuits against the highest fire hazards in the area. As a backup suppression system, a sprinkler nozzle is also installed above one train of ASW pump and exhaust fan circuits to ensure that one train will remain available for safe shutdown in the event of a fire. Either the CO_2 system or the sprinkler head, in conjunction with local smoke detection, manual fire suppression, and "No Storage of Combustible Material" zone, will provide

adequate protection such that one train of ASW pump and exhaust fan circuits will be available for safe shutdown in the event of a fire in Fire Area IS-1/Fire Zone 30-A-5 (Reference DCPP Fire Hazards Appendix R Evaluation (FHARE) 110 and FSAR Update Appendix 9.5A).

14. Multiple Procedure Change
ECG 18.6 - Recission, ECG 18.1, Rev. 3, and ECG 18.1, Rev. 4, (Units 1 & 2) (LBIE Log No. 97-174)

Equipment Control Guideline (ECG) 18.6 was rescinded because the Halon fire suppression system was removed from the solid state protection system (SSPS) room. ECG 18.1 was revised to delete the reference to Halon. The detection panel alarms, and ventilation damper controls associated with the Halon suppression system were not removed. Surveillance testing of this part of the system was unchanged. The testing requirements were relocated to ECG 18.3.

The Halon fire suppression system was removed from the SSPS room because the Halon fire suppression system is no longer necessary to provide automatic fire suppression to the SSPS room. Current analysis assumes the loss of an SSPS train as the result of a fire. Manual actions and redundant safe shutdown components are credited for mitigating the effects of a fire in this area. Halon is no longer commercially available due to environmental concerns over release of hydrofluorocarbons into the atmosphere.

Physical changes were made by DCP M-049295/050295, Rev. 0.

Safety Evaluation Summary

This 10 CFR 50.59 safety evaluation was prepared because OP1.DC16 requires a safety evaluation for all ECG revisions.

In a meeting on January 30, 1997, the NRC concurred with PG&E's approach to evaluate and remove the Halon system based on DCPP license conditions and on performance of a 50.59 safety evaluation.

The safety evaluation performed for this ECG change is based on the evaluation performed for Design Change Packages (DCPs) M-049295 and M-050295 and approved by the DCPP Plant Staff Review Committee (PSRC) on August 13, 1996.

The Halon fire suppression system is designed to mitigate the consequences of a fire. Removal of the SSPS room Halon suppression system does not change combustible loading or ignition controls in the SSPS room. The design basis accident is a fire, and removal of the SSPS room will not increase the probability of a fire in the SSPS room or any other fire area.

Consequences of a fire in the SSPS room are not increased by removal of the Halon system because current analysis assumes loss of a SSPS train as a result of a fire. The safe shutdown analysis credits operators with manually tripping the reactor from the control room. DCPP Fire Hazards Appendix R Evaluation (FHARE) 112 credits manual actions and redundant safe shutdown components for mitigating the effects of a fire in this area, and for providing the capability to achieve and maintain safe shutdown.

Possibility, probability, and consequences of other accidents or equipment malfunctions are not increased. Once the reactor is tripped, equipment in the SSPS is not required to maintain safe shutdown. If there is a fire in the SSPS room, FHARE 112 credits operator action to trip the reactor from the control room.

15. <u>Fire Rated Assemblies</u>
ECG 18.7, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-202)

This Equipment Control Guideline (ECG) revision modifies Surveillance Requirement (SR) 18.7.1 to extend the frequency for inspecting fire rated assemblies inside containment from every 18 months to every 24 months to be consistent with 24 month refueling cycles. Performance of this surveillance is necessary due to the rated enclosures being located in the containment and as low as is reasonably achievable (ALARA) considerations.

Safety Evaluation Summary

Fire rated assemblies are designed to mitigate the consequences of fires and do not cause an accident. This change does not alter the way any important-to-safety structure, system, or component functions, nor does it change the manner in which the plant is operated. Increasing the surveillance interval for the containment fire related enclosures does not result in any physical modifications to either the barrier or any important to safety structure, system, or component. This change does not alter the intent, scope, or method by which the surveillance is presently conducted.

The fire rated assemblies are not addressed in any Technical Specification (TS) or associated with any margin of safety. The increased surveillance frequency does not impact the operation of any fire protection system or component, and does not affect the operation of equipment protected by the enclosure. Therefore, this change does not involve a reduction in margin of safety as defined in the TS.

16. Radioactive Liquid Effluent Monitoring Instrumentation
ECG 39.3, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-148)

This Equipment Control Guideline (ECG) changes the channel check frequency for the Oily Water Separator (OWS) Flow Recorder (FR)-251, as required by Surveillance Requirement (SR) 39.3.1, from “24 Hours” to “daily.” This change is needed to eliminate some unnecessary OWS manual pump downs that are done only to perform the FR-251 channel check.

Safety Evaluation Summary

Changing FR-251 channel check frequency from 24 hours to daily does not change the way that FR-251 performs its required function. FR-251 does not initiate an accident, but is intended to provide a flow measurement in the event radioactive material is released due to some other condition in the plant. The daily channel check will provide, over time, the same number of required periodic channel checks as the current requirement.

The maintenance history of FR-251 shows that this instrument is very reliable. Since corrective maintenance was last performed on the instrument in 1992, it has passed all of its quarterly functional surveillance tests satisfactorily. Consequently, FR-251 is not expected to fail in between channel checks, even if they are performed as much as 48 hours apart over a two day period. There are no Technical Specification (TS) requirements or TS bases for the OWS. Therefore, there is no reduction in the margin of safety.

17. ATWS Mitigation System Actuation Circuitry
ECG 4.1, Rev. 2XPR (Units 1 & 2) (LBIE Log No. 97-188)

This Equipment Control Guideline (ECG) revision changes the applicability from Mode 1 above 40 percent turbine power to Mode 1 above 40 percent reactor power. This change brings ECG 4.1 into compliance with the licensing basis for the anticipated transient without scram (ATWS) mitigation system actuation circuitry (AMSAC) system. The licensing basis is contained in the safety evaluation for the AMSAC system. The safety evaluation assumes AMSAC is armed when reactor power is above 40 percent. The current AMSAC arming setpoint (C-20) of 40 percent turbine power is equivalent to approximately 46 percent reactor thermal power (RTP). The current AMSAC setpoint is within the design limits of the system, but is not within the licensing basis which assumes 40 percent RTP.

Safety Evaluation Summary

AMSAC is designed to mitigate the consequences of an ATWS event and is not an accident initiator. An ATWS event is not a design basis event analyzed in FSAR Update Chapter 15, but AMSAC is a licensing requirement specified by 10 CFR 50.62 and is documented in the FSAR Update. This change does not affect the design or configuration of AMSAC, but changes the alarming setpoint to agree with the AMSAC safety evaluation. There is no change in the way AMSAC operates other than the power level at which it becomes armed. This change restores the assurance that the fuel cladding will perform its required function. This change reduces the potential for voiding in the reactor vessel in the event of an ATWS, thereby assuring that the fuel remains cooled.

AMSAC is not addressed in the Technical Specifications, but this change lessens the consequences of an ATWS event and increases the margin of safety.

18. Steam Generator Level and Pressure Instruments (Appendix R) - Surveillance Requirement 4.2.2
ECG 4.2, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-159)

This Equipment Control Guideline (ECG) change revises the steam generator (SG) level and pressure instruments surveillance requirements (SRs) to change the surveillance frequency from at least once every 18 months to at least once per refueling interval. The SG instrumentation covered by this ECG provides alternate monitoring and indication capability in the event of a fire in the control room or the cable spreading room.

Safety Evaluation Summary

This change does not alter the way any important to safety structure, system, or component (SSC) functions, nor does it change the manner in which the plant is operated. There are no physical modifications to either the SG level and pressure instruments or any important-to-safety SSC. Increasing the surveillance interval does not alter the operation of the instruments, the intent or the method by which the surveillance is conducted, or the scope or intent of the associated surveillance test procedures. It does not adversely affect safety function performance, or alter the intent or method by which surveillance tests are performed.

The instruments will continue to effectively perform their design function for the longer operating cycles, and there is no time dependency associated with the encountered component failures. There is inherent substantial redundancy and other periodic checks that help ensure sufficient availability of these instruments to perform their design functions. These instruments are not required to be operable by the Technical Specifications. Therefore, this change does not involve a reduction in the margin of safety.

19. Technical Support Center ERDS
ECG 52.2, Rev. 2 (Units 1 & 2) (LBIE Log No. 96-031)
ECG 52.3, Rev. 1 (Units 1 & 2) (LBIE Log No. 96-032)

Design Change Packages (DCPs) J-49246 and J-50426 establish the emergency response facility data system (ERFDS) within the plant process computer (PPC). The PPC performs the functions of data acquisition, display, recording and recall as required by DCPP commitments to NUREG-0696 and NUREG-0737, Supplement 1. This change is made to upgrade the data systems with equipment that performs the required functions, with high reliability.

Safety Evaluation Summary

A PPC subsystem, ERFDS, is a monitoring system isolated from the plant input instrumentation. These systems do not control plant equipment and are electrically isolated from data input uses. The PPC/ERFDS provide data to the control room, technical support center, and emergency operations facility during accident response and is used as input in decision-making following accidents. The PPC/ERFDS cannot create an accident or cause a malfunction of equipment important to safety. There is no decrease in the margin of safety.

20. Reactor Coolant System (RCS) Instrumentation (Appendix R)
ECG 7.1, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-150)

This Equipment Control Guideline (ECG) change revises the reactor coolant system (RCS) instrumentation (Appendix R) ECG Surveillance Requirement

(SR) 7.1.2 to change the surveillance frequency from at least once every 18 months to at least once per refueling interval. The pressurizer pressure and pressurizer level instrument channels covered by this ECG are located on the dedicated shutdown panel (DSP). These devices provide alternate monitoring and indication capability in the event of a fire in the control room or the cable spreading room.

Safety Evaluation Summary

This change does not alter the way any important-to-safety structure, system, or component (SSC) functions and does not change the manner in which the plant is operated. There are no physical modifications to the instrument channels, or to any SSC. Increasing the surveillance interval does not alter the operation of these instrument channels, the intent or the method by which the associated surveillances are conducted, or the scope or intent of the associated surveillance test procedures. It does not affect safety function performance, or alter the intent or method by which surveillance tests are performed.

The instrument channels will continue to effectively perform their design function for the longer operating cycles. There are no indications that any of the identified RCS instrumentation failures are cycle-length dependent. There is no safety analysis impact since this change does not affect any safety limit, protection system setpoint, or limiting condition for operation.

21. Power-Operated Relief Valve (PORV) Emergency Close at the Hot Shutdown Panel (HSP) (10 CFR 50, Appendix R) - Surveillance Requirement 7.2.1
ECG 7.2, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-151)

This Equipment Control Guideline (ECG) change revises the PORV emergency close at the HSP (Appendix R) ECG surveillance requirement (SR) to change the surveillance frequency from at least once per 18 months to at least once per refueling interval. The PORV emergency close control circuits covered by this ECG provide an alternate method of closing the PORVs in the event of a fire in the control room and/or the cable spreading room.

Safety Evaluation Summary

This change does not alter the way any important to safety structure, system, or component (SSC) functions and does not change the manner in which the plant is operated. There are no physical modifications to the control circuitry, or to any SSC. Increasing the surveillance interval does not alter the operation of these control circuits, the intent or the method by which the associated surveillances are conducted, or the scope or intent of the associated surveillance test procedures. It does not affect safety function performance, or alter the intent or method by which surveillance tests are performed.

The PORV emergency close control circuits will continue to effectively perform their design function for the longer operating cycles. No failures have been encountered during the functional testing of this circuitry, and there is no evidence that the performance of these control circuits is time dependent or that the longer surveillance interval will adversely affect the performance of these switches.

22. Safety Valves - Shutdown
ECG 7.3, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-079)

Revision 1 to Equipment Control Guideline (ECG) 7.3 updates the ECG Bases to document the current method for testing pressurizer safety valves. The valves are tested in accordance with Westinghouse report WCAP 12910, Rev. 1A, "Pressurizer Safety Valve Set Pressure Shift," dated March 1993.

Safety Evaluation Summary

Revision 1 to ECG 7.3 updates the ECG Bases to reflect the current approved method for pressurizer relief valve testing. The revision does not modify the ECG itself. The ECG 7.3 requirements were relocated from Technical Specifications as approved by License Amendments 98/97. Therefore the ECG Bases revision does not involve an unreviewed safety question.

23. Positive Displacement Pump (PDP)
ECG 8.1, Rev. 3 (Units 1 & 2) (LBIE Log No. 97-171)

This Equipment Control Guideline (ECG) revises the allowed outage time (AOT)from 7 days to 14 days each calendar year to perform overhaul work on the positive displacement pump (PDP). A 7-day AOT does not allow sufficient time to perform an overhaul, without obtaining an AOT extension.

Safety Evaluation Summary

The increased AOT from 7 days to 14 days once per year to overhaul the pump does not change the operating methods or practices for the PDP. The increased

AOT does not result in any changes to hardware or equipment associated with the PDP. It will continue to operate and be operated as it is currently. The PDP is not an accident initiator, but is designed to allow the plant to achieve safe shutdown if a fire were to occur in the centrifugal charging pump (CCP) room such that both CCPs were disabled. The increased AOT to allow the performance of maintenance will increase the overall reliability of the PDP.

The PDP is not Technical Specification required equipment and is not credited in any FSAR Update Chapter 15 design basis accident analysis as mitigation equipment. Therefore, the increased AOT will not result in a reduction in the margin of safety as defined in the basis for any Technical Specification.

24. Centrifugal Charging Pump (CCP) Backup Firewater Cooling
ECG 8.3, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-009)

This change creates a new Equipment Control Guideline (ECG) to provide administrative controls for backup firewater cooling to CCPs. An analysis that supports the DCPP Security Plan takes credit for the CCP backup firewater cooling system to meet vehicle barrier security requirements.

Safety Evaluation Summary

The CCP backup firewater cooling system is a design feature that allows the CCPs to provide cooling to the reactor coolant pump (RCP) seals in the event of complete loss of auxiliary saltwater (ASW) system. It is a mitigation system and not an accident initiator. However, it is not credited in the FSAR Update for mitigating any accident.

This new ECG places existing administrative controls for the CCP backup firewater cooling system, plus a new monthly surveillance requirement (visual inventory), under the controls of the ECG program specified by procedure OP1.DC16. The only equipment important to safety affected by these controls are the CCPs.

Creation of the ECG and its associated surveillance requirements (SRs) provides assurance that consequences of loss of both ASW trains due to vehicle damage of the trains will not increase the probability or the consequences of a small break loss-of-coolant accident by assuming that this backup method of cooling the CCPs, and consequently the RCP seals, is available. None of these controls are included in Technical Specifications. Therefore, there is no reduction in margin of safety as defined in the basis for any Technical Specification.

25. Safety Injection – Accumulator Pressure and Water Level Instrumentation
ECG 9.1, Rev. 1 (Units 1 & 2) (LBIE Log No. 96-040)

This Equipment Control Guideline (ECG) revision makes a distinction between surveillance requirements for narrow range (NR) and wide range (WR) safety injection (SI) accumulator water level channels. Previously, ECG Surveillance Requirement (SR) 9.1.1 required a channel functional test (CFT) on a 31-day frequency for pressure and NR level channels, but did not apply to WR level. However, WR level is part of Regulatory Guide 1.97 post accident monitoring (PAM) requirements. Other PAM instruments receive a channel calibration on a refueling outage frequency (18 months in Rev. 1; 24 months in Rev. 2). SR 9.1.2 was clarified to add WR level channel calibration on an 18-month frequency.

Safety Evaluation Summary

The SI accumulator WR level channels are for PAM indications only. They do not provide input to any engineered safeguards features (ESF) function required for accident mitigation. Neither can the channels initiate any accident. The channels are used following an accident to provide a qualitative indication of whether an accumulator has injected. The indication itself has no effect on the consequences or management of an accident.

Clarification of SI accumulator WR level surveillance requirements has no impact on the frequency or consequences of any accident or equipment malfunction as evaluated in the FSAR Update. The WR level channels are not part of any Technical-Specification-required function and are not used to establish operating level in the accumulators; there is no impact on any Technical Specification safety margin.

26. Snubbers
ECG 99.1 (Units 1 & 2) (LBIE Log No. 97-085)

This Equipment Control Guideline (ECG) change was performed to alter the snubber functional testing frequency from 18 to 24 months during shutdown to coincide with the 24-month fuel cycle.

Safety Evaluation Summary

This change in surveillance frequency was determined to be in compliance with the ASME/ANSI OM Part 4, OMa-1988 addenda to the OM-1987 Edition, which states: "Testing shall take place at least every refueling outage using a sample of snubbers." In 1993 an ASME/ANSI OM-4 task group completed a review of the surveillance frequency, in light of reactor facilities extending fuel cycles to 24 months and concluded the code is applicable for the 24-month cycle. A review of the test results from the most recent nine refueling outages at DCPP showed a test failure rate of less than 1 percent and in all those cases the piping had remained operable with the failed snubber. This low testing sample failure rate and the ANSI OM-4 study showed that the proposed frequency will maintain a high confidence level in snubber operability.

27. Snubbers
ECG 99.1, Rev. 3 (Units 1 & 2) (LBIE Log No. 97-187)

This Equipment Control Guideline (ECG) revises the surveillance frequency for functional testing and service life monitoring of snubbers, as specified in Surveillance Requirements (SRs) 99.1.3 & 99.1.7, from 18 months to 24 months to be consistent with 24-month fuel cycles.

Safety Evaluation Summary

Snubbers are designed to limit pipe movement during design basis seismic events and are not accident initiators. This change does not affect the way in which the snubbers operate. Also, this change complies with the ASME/ANSI OM Part 4 code requirements.

A review of snubber operational, maintenance, and surveillance testing history has demonstrated that the snubbers are reliable and can be expected to perform their required function when tested on a 24-month interval. The snubber test failure rate has been less than 1 percent over the past nine refueling outages and in each case of snubber test failure, the piping analysis has shown that the piping remained operable. This low sample test failure rate combined with additional tests performed for service life monitoring provides a high confidence level in snubber operability using the sampling test methods prescribed in ASME/ANSI OM Part 4. Therefore, this change does not involve a reduction in margin of safety as defined for any Technical Specification.

F. FSAR Update Changes

1. NIS Detector Description
FSAR Update 4.4.5.3 (LBIE Log No. 98-002)

FSAR Update Section 4.4.5.3 describes the positioning of the nuclear instrumentation system (NIS) detectors around the reactor core. This section states, "The two positions opposite the other two flat positions of the core are spare instrumentation wells." These instrumentation wells in fact house the post-accident neutron flux monitor detectors.

Safety Evaluation Summary

This FSAR Update change corrects the description of the NIS detector well arrangement. No physical modifications or design changes are required. There is no accident evaluated in the FSAR Update that is affected by changing the description of the NIS detector placement. Equipment operation and function remains the same. No technical specifications changes are required. The margin of safety is not affected by changing the NIS detector placement description in the FSAR Update.

2. Change Testing Methodology for P-8 Blocking Function
FSAR Update 7.2.2.2.1.7(2) (LBIE Log No. 98-001)

The testing description in FSAR Update Section 7.2.2.2.1.7 was changed to reflect the manner in which the P-8 blocking function is tested. This was required when it was discovered that the P-8 block is not tested by the SSPS semi-automatic tester. A commitment was made in PG&E letter DCL-97-172 to test the P-8 function using other means, a description of which was added to FSAR Update Section 7.2.2.2.1.7.

Safety Evaluation Summary

The FSAR Update change clarifies the test method described in the FSAR Update. The additional testing to verify the P-8 block function is performed when the solid-state protection system (SSPS) train is removed from service. No accidents previously evaluated are affected by clarifying the SSPS test methodology. Since testing is performed with the SSPS train out of service the probability of a malfunction of equipment important to safety is not increased. No physical modifications are performed. No Technical Specification changes are required. The additional testing satisfies the requirements of Technical Specification 4.3-1, item 22.

3. Subcooled Margin Monitor
AR A0427405 (LBIE Log No. 97-067)

This change corrects information in FSAR Update Table 7.5-5, “Information Required on the Subcooling Meter,” concerning:

- The uncertainty of the input parameters (reactor coolant system (RCS) coolant temperature and pressure)
- The uncertainty in the digital readout meter
- The range of RCS pressures that the digital readout meter uncertainty is applicable

Safety Evaluation Summary

The uncertainty (input signals and digital readout) information was updated to reflect the calculations revised as part of the Extended Fuel Cycle project. These calculations used DCPP specific calibration data to model equipment performance for both 18- and 24-month fuel cycles. The digital readout meter uncertainty applicability limitation was added based on a 1986 Westinghouse commitment to the NRC on subcooled margin monitor (SMM) accuracy requirements.

The proposed changes to the FSAR Update Table 7.5-5 accuracy statements provide an envelope for the expected control room indication uncertainty. The proposed changes will provide realistic control room indication accuracy statements in compliance with the requirements of Regulatory Guide (RG)1.70, Revision 1. An evaluation of the control room indication accuracy has been performed as follows:

The text of the FSAR Update does not indicate that range and accuracy information included in Table 7.5-5 is based on an operational requirement of DCPP. However, the PG&E has evaluated the proposed changes with respect to the design requirements established in DCPP design basis documents. This evaluation identified no adverse impact on the design bases of DCPP.

4. Substitution of Alternate Fire Protection Features for Unqualified 3-Hour Fire Barrier
FSAR Update Appendices 9.5A and 9.5H (LBIE Log No. 96-006)

The qualification of the Pyrocrete and 3M material used as a 3-hour fire barrier was determined to be questionable. 10 CFR 50, Appendix R, Section III.G.2.b, allows crediting other means of meeting the required separation of redundant circuits credited for safe shutdown in the event of a fire. Specifically it allows crediting a 20-foot horizontal separation with no intervening combustibles or fire hazards, coupled with installation of fire detectors and an automatic fire suppression system in the fire area. All of these alternate requirements are met for the auxiliary saltwater (ASW) pump and exhaust fan circuits in Fire Area IS-

1/Fire Zone 30-A-5.. These include local smoke detectors, overhead sprinkler heads, and local heat-activated carbon dioxide suppression systems. To ensure the operability of these detectors and suppression systems that are now being credited to meet Appendix R requirements in lieu of the 3-hour fire barrier, they have been brought under formal administrative control by adding them to the appropriate equipment control guideline

Safety Evaluation Summary

Meeting these alternate requirements ensures that at least one of the redundant ASW trains in each unit will remain operable in the event of a fire at any location in the fire area. There is no decrease in safety because in the event of a fire, the NRC has determined that the alternative measures being instituted provide equivalent protection against a fire to the fire protection measure being replaced.

5. Post-LOCA Hydrogen Generation
FSAR Update Appendix 6.2C (LBIE Log No. 97-212)

This change reflects a revised analysis performed by Westinghouse using more representative, yet conservative, assumptions for hydrogen concentration and amounts of aluminum and zinc in the containment. Specifically, the post-LOCA hydrogen concentration was increased from 35 to 60 cc/kg to envelope an anticipated change in procedures to increase the maximum concentration from 40 to 50 cc/kg to account for measurement uncertainty. Also, the allowed aluminum content was reduced from 4,076 to 3,576 lbm and the allowed zinc increased from 44,305 to 48,884 lbm.

Safety Evaluation Summary

Appendix 6.2C of the FSAR Update describes post-LOCA hydrogen generation in the containment. There is a licensing commitment to operate the hydrogen recombiners in such a manner as to keep the hydrogen concentration below 3.5 percent by volume. The revised analysis performed by Westinghouse demonstrates that the hydrogen limit continues to be met. Placing this revised analysis in the FSAR Update is within the licensing basis and there is no unreviewed safety question.

6. Timing for Main Feedwater Pump Trip After MSLB
FSAR Update Appendix 6.2C (LBIE Log No. 97-220)

This change clarifies Appendix 6.2C by adding a sentence to the discussion regarding the time available for the main feedwater pump to trip following a main steam line break. The sentence added is, "The analysis uses a feedwater flow curve that indicates feedwater pump trip at 2 to 2.5 seconds, but evaluation in Reference 14 of the total conservatism in the feedwater flow curve shows that up to 5 seconds time to receive the isolation signal is acceptable." Reference 14 is a letter from Westinghouse to PG&E documenting that the analysis in WCAP-13908 bounds an isolation signal time as long as 5 seconds.

Safety Evaluation Summary

The added information is a clarification of an accident analysis assumption statement. The analysis assumption, is not changed or any of the accident results or conclusions. Therefore, no unreviewed safety question is involved.

7. Installation of 3-Hour Rated Fire Damper
FSAR Update Appendix 9.5A (LBIE Log No. 97-127)

The fire hazards analysis for Fire Areas S-7 and TB-12 in Fire Zone 23-C in FSAR Update Appendix 9.5A was revised to reflect the existence of a 3-hour rated fire damper in the heating, ventilation, and air conditioning (HVAC) ductwork connecting these two area. The previous description indicated that the duct was undampered. The 3-hour rated damper was installed in 1983, but the change was not reflected in the FSAR Update.

Safety Evaluation Summary

A safety evaluation was not written for the change at the time because Unit 2 had not yet received its operating license. The existence of the 3-hour barrier in the duct serves to prevent the spread of a fire in one area to another area, and hence serves to reduce the consequences of a fire.

8. Fire Barrier Descriptions
FSAR Update Appendix 9.5A (LBIE Log No. 98-092)

Errors in fire barrier descriptions have been corrected to reflect current plant configurations. No design changes, procedure changes, or calculation changes are associated with this FSAR Update change.

Safety Evaluation Summary

The changes are being made to conform the FSAR Update with the current plant configuration. No new fire hazards are being introduced and no designs,

calculations, or procedures are being revised. The radiological consequences of a fire or accident are not affected and no physical changes to the plant are involved. Based on the evaluation, it is concluded that no unreviewed safety question is involved.

9. Fire Protection - Reactor Coolant Pump (RCP) Lube Oil Collection System
FSAR Update Appendix 9.5C (LBIE Log No. 97-097)

Appendix 9.5C of the FSAR Update was revised to refer to a deviation, rather than an exemption, from the requirements of Appendix R for the reactor coolant pump (RCP) oil collection system. The appendix was also revised to change the oil flashpoint temperature 480°F to 425°F.

Safety Evaluation Summary

The deviation from 10 CFR 50, Appendix R, involves use of a common lube oil collection tank in lieu of dedicated collection tanks for each reactor coolant pump (RCP). Changing the terminology from “exemption” to “deviation” is an administrative change. Reducing the flashpoint temperature to 425°F is evaluated in DCPP fire hazards Appendix R evaluation (FHARE) 115, where it is concluded that the lower flashpoint temperature does not affect the basis for the deviation or the safe shutdown analysis. Therefore, it is concluded that no unreviewed safety question is involved.

10. Fire Protection Program Administration
FSAR Update Appendix 9.5H (LBIE Log No. 97-138)

FSAR Update Appendix 9.5H was revised to update organization and responsibilities descriptions, update the list of procedures, delete operating and surveillance requirements that are verbatim to existing Equipment Control Guidelines (ECGs), and add a list of ECGs that are related to rire protection systems, 10 CFR 50, Appendix R, and ECG bases. This change was made to reflect current DCPP fire protection system controls.

Safety Evaluation Summary

The FSAR Update change was made to reflect current administration of the DCPP fire protection program. There was no effect on plant operation. No accident (fire or design basis accident) or equipment malfunction probabilities or consequences were affected.

11. Tornado Failure Analysis Table
FSAR Update Chapter 3, Table 3.3-3 (LBIE Log No. 97-175)

This FSAR Update change corrected the tornado failure analysis table, which stated that the automatic make-up valves would fail open on a loss of instrument

air resulting from a tornado. The actual system response of the make-up valves is to fail closed on a loss of air.

Safety Evaluation Summary

This evaluation bases its conclusion on the fact that automatic makeup is not required for component cooling water (CCW) to continue operating during a postulated tornado because other system leakage is not required to be postulated during the tornado. The normal position of the make-up valves is closed. If make-up water were desired after a postulated tornado had damaged the instrument air lines, the make-up valve can be manually bypassed to provide make-up.

12. Reactor Coolant System
FSAR Update Chapter 5 (LBIE Log No. 97-016)

FSAR Update Section 5.4.3 was changed from, “The storage racks are then removed from the refueling cavity and stored at convenient locations on the containment operating deck prior to reactor closure removal and refueling cavity flooding” to “The storage racks are then removed from the refueling cavity for maintenance and inspection prior to reactor closure removal and refueling cavity flooding.” This change was made because closure studs are normally stored outside containment during refueling.

Safety Evaluation Summary

The purpose of Section 5.4.3 is to explain that closure studs are protected from exposure to borated refueling cavity water by removing them from the refueling cavity before the cavity is flooded with borated water. Changing the storage location does not increase the chances of exposure to borated refueling cavity water. Floor loading and missiles outside of containment, in general, have already been evaluated.

13. Electrical Power and Emergency Lighting FSAR Discrepancies
FSAR Update Chapters 8 and 9 (LBIE Log No. 97-019)

This is a general revision to the electrical sections of the FSAR Update. The general revision provides clarification of as-built configurations and consistency with existing procedures. There are no physical changes associated with this revision.

Safety Evaluation Summary

There was an inconsistency in the voltage, frequency, diesel generator speed, and nomenclature used to describe the requirements when the diesel generator energizes the bus. These changes do not increase the probability of an

accident, since they have been changed to be consistent with the Technical Specification, design basis, and accident analysis. The remaining items do not increase the probability of an accident because they are changes to systems and components that do not affect the operability of ESF loads or are editorial in nature.

The changes do not adversely change the operation or maintenance of any equipment that could result in the malfunction of any equipment important to safety. The changes do not result in any physical change or procedural change that could result in the malfunction of any equipment important to safety.

14. 12-kV Cable Spreading Room Transite Panels," Pyrocrete Enclosure Doors, and Fire Hazards Analysis
FHARE 17 and 55, FSAR Update Appendix 9.5A (LBIE Log No. 98-005)

Because the original safe shutdown analysis conservatively assumed a loss of offsite power concurrent with a fire, most of the pyrocrete barriers and one plaster barrier were installed in certain fire areas to protect circuits associated with diesel generators and diesel fuel oil pump operation to ensure that an onsite power source was available for safe shutdown. Based on the revised safe shutdown methodology in Calculation M-680, the safe shutdown analysis for the affected fire areas were reviewed to determine if the fire barrier will still need to protect emergency diesel generator and/or diesel fuel oil pump circuits. As a result of the review, it was determined that offsite power would be available for shutdown in the event of a fire in the affected areas. As a result of not crediting the pyrocrete barriers, two fire hazards Appendix R evaluations (FHAREs) associated with pyrocrete enclosures are no longer required. This change was previously discussed with the NRC on September 17, 1997, and it was determined that this change could be evaluated via the safety evaluation process and would not require prior NRC approval for changing the assumptions related to offsite power.

Safety Evaluation Summary

The changes made to the FSAR Update and revisions to FHAREs reflect the results of the safe shutdown analysis. These changes incorporate the corrective actions completed for NCR N0001887. Not crediting the fire-rated enclosures in some fire areas complies with the requirements of Appendix R, Section III.G. for separation of circuits. These changes will not increase fire hazards, ignition sources, or operation of fire protection equipment and safety-related equipment. Based upon the above criteria and justification, an unreviewed safety question is not involved. Also a change to the DCPP Technical Specifications is not involved.

15. System Performance Evaluation
FSAR Update Section 6.2.3.3.5 (LBIE Log No. 97-122)

The changes made are removing an incorrect reference and corrections to text in Section 6.2.3.3.5 that describes values used to determine the unsprayed volume of “approximately 17 percent” inside containment. Although the value of the unsprayed volume has not changed, the input parameters used to determine the unsprayed volume have been corrected to account for occupied volume above the deck, credit for sprayed refueling cavity volume, and mixing above the spray ring headers. This is a document change only, there is no physical change to the plant and no affect on procedures, plant operations, or accident analysis

Safety Evaluation Summary

This change is to the method of establishing one of the parameters used to evaluate the performance of a safety system to mitigate an accident. The corrections to the input parameters did not change the value of the unsprayed volume, and therefore the analysis of the iodine removal capability of the containment spray is unaffected. So the consequences of accidents remain unchanged.

16. Electrical Bus Configuration During Modes 5 and 6
FSAR Update FSAR Update Chapter 8, Section 8.3.1 (LBIE Log No. 97-176)

This section describes allowed 4-kV, 120-Vac and 125-Vdc bus configurations during Modes 5 and 6. The revision was to clarify the allowed configurations.

This change has been superseded by another change and its evaluation.

Safety Evaluation Summary

The proposed revision clarifies configurations allowed by existing procedures. As noted, this change has been superseded.

17. Low-Pressure Turbine Exhaust Hood Spray Operation
FSAR Update Section 10.2.1.3 (LBIE Log No. 97-161)

The operation description in the FSAR Update for low-pressure exhaust hood spray was changed to better reflect the recommendations and parameters included in the vendor manual, for proper spray operation during plant operation.

Safety Evaluation Summary

This change was performed for clarification, because the description and parameters included in the annunciator response procedure for the operation and parameters of the low pressure turbine exhaust spray did not match the description and parameters contained in the FSAR Update.

This change did not create or increase the frequency of an accident different from those previously evaluated in the FSAR Update. This system is not addressed in the Technical Specifications nor Equipment Control Guidelines. This system does not affect or have inputs to or from any safety related system, systems important to safety, or any protection system for the turbine and reactor.

18. Clarification of the Leak Rate Requirements for Main Steam System Isolation Valves
FSAR Update Section 10.3 (LBIE Log No. 97-064)

Local leak rate testing of valves that isolate main steam system containment penetrations is not required by 10 CFR 50, Appendix J, Section II.H, or by FSAR Update Table 6.2-39, “Containment Piping Penetrations and Valving.” However, some wording in FSAR Update Section 10.3 could have been interpreted to imply that such testing is performed. This wording was revised to remove that potential for misinterpretation and make it clear that such testing is not required.

Safety Evaluation Summary

Such testing is not needed because the main steam system inside containment is a seismically analyzed closed system whose pressure boundary integrity is verified during the containment integrated leak rate test and is not damaged during a loss-of-coolant accident (LOCA), so that post-LOCA containment atmosphere cannot enter that system and escape from the containment via that system's penetrations. Following a steam generator tube rupture accident, the contribution to offsite doses through the subject leakage paths is negligible compared to that through the stuck open 10 percent atmospheric steam dump valve assumed in the FSAR Update accident analysis, and hence need not be considered to be a contributor to offsite dose for this accident. Since leakage through these flow paths is not a contributor to offsite dose, there is no effect on the consequences of an accident as a result of not local leak rate testing them, as allowed by 10 CFR 50, Appendix J, and FSAR Update Table 6.2-39.

19. Increase Steam Generator Blowdown
FSAR Update Section 10.4.8 (LBIE Log No. 97-218)

An engineering evaluation shows that the blowdown to the steam generator blowdown tank (SGBD) can be increased during plant startup and other plant evolutions. The system is designed for 150 gpm continuous blowdown, but can be increased to 320 gpm during plant startups following plant shutdowns in excess of 72 hours.

Safety Evaluation Summary

The SGBD sysem components have been shown by calculation to be able to accommodate the increased blowdown flow. As SGBD piping is 6 inches or smaller, pipe breaks are in the category of minor secondary system pipe breaks. Even with the increased flow, the consequences of pipe failures are bounded by high-energy line breaks associated with either main steam or main feedwater line ruptures. The flow increase has also been shown to be acceptable from an erosion/corrosion standpoint. Therefore, it is concluded that the change does not involve an unreviewed safety question.

20. Gaseous Radwaste System Parameter Change
FSAR Update Section 11.3 and Table 11.3-1 (LBIE Log No. 96-024)

This FSAR Update revision made minor changes to the design and operating parameters of the gaseous radwaste system components described in the referenced table.

Safety Evaluation Summary

This change has no safety impact because there is no change to the equipment and these values were not used in any analysis or licensing basis. The gaseous radwaste system equipment involved with this change is not involved with the gaseous sadwaste accident analyzed in FSAR Update Chapter 15.

21. Mobile Radwaste Processing System
FSAR Update Section 11.5.4.4 (LBIE Log No. 98-074)

This change corrects the FSAR Update by eliminating reference to interlocks and control signals for the mobile radwaste processing system (MRPS), features that the MRPS does not have.

Safety Evaluation Summary

The MRPS is manually operated in accordance with procedures to prevent overflow and spills. Any spill would be contained in the bermed pad and sump for return to the radwaste system. Radwaste overflow accidents are not evaluated in the FSAR Update and there is no need for interlocks and automatic control signals. Therefore it is concluded that this change does not involve an unreviewed safety question.

22. Additional Operations Directors
FSAR Update Section 13.1.2.2.2.1 (LBIE Log No. 98-016)

The change involves appointment of an additional Operations director for periods of high workload.

Safety Evaluation Summary

Appointment of an additional director is an administrative change that does not affect the accidents evaluated in the FSAR Update. Therefore, it is concluded that this change does not involve an unreviewed safety question.

23. Technical Specifications and Equipment Control Guidelines
FSAR Update Section 16.1 (LBIE Log No. 97-101)

In letter DCL-95-222, dated October 4, 1995, PG&E submitted License Amendment Request (LAR) 97-07 that proposed to relocate several Technical Specifications (TSs) to Equipment Control Guidelines (ECGs) and to reference the ECGs in the FSAR Update. During review of LAR 97-05, the NRC staff requested PG&E to add the following wording to FSAR Update Section 16.1:

"ECGs containing relocated TSs are incorporated into the FSAR Update, by reference, in Table 16.1-1.

"For ECGs listed in Table 16.1-1, if the equipment cannot be returned to service as required by the ECG, then a review in accordance with 10 CFR 50.59 is required."

Safety Evaluation Summary

These changes place increased administrative controls on ECGs that are relocated from TSs, but do not change the ECG requirements themselves.

24. Equipment Control Guidelines
FSAR Update Section 16.1 (LBIE Log No. 98-061)

Nine Technical Specifications have been relocated to Equipment Control Guidelines (ECGs) and added to FSAR Update Table 16.1-1 pursuant to License Amendments 120 and 118 dated February 3, 1998.

Safety Evaluation Summary

Adding the nine ECGs to FSAR Update Table 16.1-1 is an administrative change that has no safety or licensing basis implications. Therefore, it is concluded that no unreviewed safety question is involved.

25. Delete Precipitation Gauge Tipping Bucket Accuracy
(LBIE Log No. 97-017)
FSAR Update Section 2.3.3.4 (LBIE Log No. 98-061)

FSAR Update Section 2.3.3.4 specified the accuracy of the precipitation guage tipping bucket. This accuracy specification is excessive detail and is not consistent with other FSAR Update sections. Design Change Package (DCP) J-49101 installed a new tipping bucket with similar but different accuracy specification. This FSAR Update change deletes all reference to tipping bucket accuracy.

Safety Evaluation Summary

Accuracy of the precipitation gauge tipping bucket does not increase the probability of occurrence of accidents. The tipping bucket accuracy is not used in modeling of any accident evaluated in the FSAR Update. The Emergency Plan is not affected by the tipping bucket accuracy. The accuracy specification in the FSAR Update does not affect other equipment important to safety. The accuracy of the tipping bucket is not used in calculating the margin of safety for any technical specification.

26. Wind and Tornado Loadings
FSAR Update Section 3.3 and Associated Tables (LBIE Log No. 97-096)

This change revises information in Section 3.3 of the FSAR Update concerning safety-related equipment potentially exposed to the effects of a tornado. The changes do not represent any physical changes to the plant or procedures. An evaluation consisting of plant walkdowns and an engineering analysis of the effects of tornado wind and/or tornado missiles was performed. The significant conclusions from this evaluation were incorporated into the FSAR Update.

Safety Evaluation Summary

The engineering evaluation and walkdowns identified safety-related equipment and component vulnerabilities to tornado and missile effects. No circumstances were found that violated the tornado licensing basis. Therefore, there is no unreviewed safety question associated with this change.

27. Wind and Tornado Loadings, (Change No. K-3.3(7))
FSAR Update Section 3.3, Table 3.3-2 (LBIE Log No. 97-073)

This change revises the discussion of the wind and tornado design of the major structures, given in FSAR Update Section 3.3, to address certain problems identified during the preparation of Design Criteria Memorandum (DCM) T-9, "Wind, Tornado, and Tsunami." The majority of the changes either correct typographical errors or are editorial. However, certain changes correct minor discrepancies in the text of the FSAR Update:

The discussion of wind loading on the turbine building in Section 3.3.1.2 was clarified to indicate that loads were developed in accordance with U.S. Navy Design Manual DM-2, not the Uniform Building Code, as was implied by the text.

Corrected a misleading statement in Section 3.3.2.1.1 to indicate that PG&E does not have a commitment to a specific design basis tornado wind speed. This statement was originally added during the preparation of the FSAR Update based on a quote from Supplement 7 to the Safety Evaluation Report, which reflected the NRC's attempt to develop a conservative estimate of the tornado wind speed for DCPP, not the wind speeds used by PG&E.

The discussion of atmospheric pressure drop values in Section 3.3.2.1.1 was expanded to include those applicable to both large and small structures.

The discussion of calculational methods used for the determination of tornado missile forces on structures in Section 3.3.2.2.2 was expanded to include those applicable to both concrete and steel structures.

Safety Evaluation Summary

These changes make the FSAR Update consistent with the information contained in the applicable DCM and the design calculations associated with wind and tornado loading. There are no physical modifications to the structures or any changes in the reported wind and tornado resistance of the structures. Therefore, the level of wind and tornado protection afforded to safety-related equipment is not changed. Hence, the ability to safely shut down the plant in the event of severe winds or tornadoes is not affected.

28. Supplemental Meteorological System
FSAR Update Section 3.3.2 (LBIE Log No. 98-077)

This change was made to describe an upgrade to the supplemental meteorological measurement system. The system was upgraded from a single-phase, non-personal computer (PC) based system to a phased array, PC-based (IBM clone) system.

Safety Evaluation Summary

The previous system had Doppler acoustic sounders installed at three locations. The new system is more accurate, effiicent, and reliable than the old system. It was determined that installing Doppler sounders at two locations would provide information equivalent to the three previous locations. Therefore, it was decided to drop the Los Osos site. As this system is only a backup for accident response assessments and is equivalent to the old system, no unreviewed safety questions exist.

29. Component Cooling Water (CCW) System Surge Tank
FSAR Update Section 3.3.2.3.2.2 (LBIE Log No. 97-068)

This change clarifies the FSAR Update description of the redundant CCW surge tank high level alarms to match actual plant configuration. Contrary to the previous description, there is only one high level alarm on the CCW surge tank.

Safety Evaluation Summary

The installed high level alarm on the surge tank is Class II and utilizes a switch and transmitter that are safety-related for pressure boundary integrity only. The high level alarm has no active safety function and is not required to mitigate an accident or prevent an off site dose release. Therefore redundant high level alarms are not required.

30. Installation of the Component Cooling Water (CCW) Surge Tank Pressurization System
FSAR Update Section 3.3.2.3.2.2 and Table 3.3-3 (LBIE Log No. 97-154)

This change was made to reflect reflect the installation of the component cooling water (CCW) surge tank pressurization system. This change also corrected a statement in the tornado failure analysis table, which incorrectly stated that a maximum of 5000 gal. would spill from the surge tank in the event of tornado damage. The actual volume is 8100 gal. Additionally, this change clarified where the discharged 8100 gal would be directed.

Safety Evaluation Summary

The physical implementation of the CCW surge tank pressurization systems was covered by the evaluations performed for Design Change Packages (DCPs) M-049284 and M-050284. This evaluation concludes that revising the FSAR Update to reflect previously evaluated approved system changes does not result in a unreviewed safety question. This evaluation also concludes that the extra volume of CCW discharged as a result of a tornado can be managed by the inside or outside drainage systems without impairing the safety functions of the CCW system or other systems.

31. Detailed Results of the Tornado Evaluation of Turbine Building
FSAR Update Section 3.3.2.3.2.8 (LBIE Log No. 97-018)

This change updates FSAR Update Section 3.3.2.3.2.8 to reflect the in-situ configuration of the tornado missile barriers in the turbine building for the emergency diesel generator air intakes. Previously the FSAR Update indicated that the original air intake louvers were immediately behind the external missile barriers, while, in reality, these louvers were removed during the installation of the missile barriers in 1975. A similar misstatement in Section 4.3.5.1.5 of Design Criteria Memorandum (DCM) T-9 is also corrected.

Safety Evaluation Summary

This change makes the FSAR Update and DCM consistent with the in-situ configuration. There are no physical modifications to the missile barriers or any changes in the reported wind and tornado resistance of the barriers. Therefore, the level of wind and tornado protection afforded to the safety related diesel generators is not changed. Hence, the ability to safely shut down the plant in the event of tornadoes is not affected.

32. High-Energy Line Break (HELB) Compartment Pressurization Time Response
FSAR Update Section 3.6 Figures (LBIE Log No. 98-098)

Some of the high-energy line break (HELB) compartment pressurization time response figures in FSAR Update Section 3.6 have been revised to correct deficiencies.

Safety Evaluation Summary

The figures being revised document the consequences of non-mechanistic HELBs. The post-HELB compartment pressures and temperatures are decreased for some compartments and increased for others, but do not exceed the environmental qualification values for equipment required to mitigate the HELB. Therefore, it is concluded that the changes do not involve an unreviewed safety question.

33. Design of Containment Structure
FSAR Update Section 3.8 and Associated Figures (LBIE Log No. 96-020)

This change updates FSAR Update Section 3.8.1 and several of the associated figures to reflect the latest analyses of the containment shell and liner plate. Containment pressure and temperature transient curves, element forces, and stresses are revised. In addition, an error in the reference to the code applicable to the design of the liner plate is corrected.

Safety Evaluation Summary

This change makes the FSAR Update consistent with the current loadings and analysis results. There are no physical modifications to the containment structure. All loads and stress levels are still well within the acceptance criteria established in the FSAR Update. Therefore, the level of accident protection provided by the containment structure is not changed. Hence, containment integrity and the ability to safely shutdown the plant in the event of a design basis accident is not affected.

34. Lighting and Communication in Containment Personnel Hatches
FSAR Update Section 3.8.1.1.3.3 (LBIE Log No. 98-068)

This change deletes the word “emergency” from the sentence describing the lighting and communications systems in the containment personnel hatches. The lighting and communications systems in the personnel hatches are “normal” systems operating from external “normal” supplies.

Safety Evaluation Summary

A review of 10 CFR 50, Appendix R, other parts of the FSAR Update, NRC Safety Evaluation Reports, pertinent NRC corespondence, and Occupational Safety and Health Administration requirements revealed no requirements or commitments for emergency lighting and communications in the personnel

hatches. Therefore, the change is within the licensing basis and no unreviewed safety question exists.

35. Mid-Loop Operation and Use of Steam Generator Nozzle Dams
FSAR Update Section 5.1.6.5 (LBIE Log No. 97-215)

A section was added to describe reactor coolant system mid-loop operation and use of steam generator nozzle dams. The addition is based on information contained in Westinghouse Technical Report, "RCS Pressurization Analysis for Diablo Canyon Shutdown Scenarios," dated April 1997.

Safety Evaluation Summary

The safety issue evaluations contained in the LBIE reference documents conclude that mid-loop operation with core decay heat no greater than 15.3 MWt will not have an adverse effect on safe operation at DCPP. Since an operating charging pump or gravity feed of the reactor coolant system from the refueling water storage tank, if required due to loss of station power, can provide sufficient inventory to maintain core cooling, the consequences of a loss of residual heat removal cooling event are considered acceptable from the standpoint of safety to operating personnel and to the general public for both high and low decay heat situations. The material added to the FSAR Update is consistent with NRC requirements and PG&E commitments to the NRC. Therefore, no unreviewed safety question exists.

36. Clarification of Water Systems Used During Refueling
FSAR Update Section 5.5.6.2.2.4 (LBIE Log No. 97-124)

Discussions related to filling the reactor cavity during refueling operations were clarified in the FSAR Update to note that several systems other than the residual heat removal (RHR) system can be used for filling and that the RHR inlet isolation valves are not closed if there is fuel in the core.

Safety Evaluation Summary

The changes made are for clarification purposes only. Uncontrolled boron dilution and dilution during refueling are not affected by this change. Therefore, no unreviewed safety question is involved.

37. Changes of Generic Discussions of Valves to Make Them DCPP Specific
FSAR Update Section 6.2 and Table 6.3-1 (LBIE Log No. 96-013)

The generic discussion of emergency core cooling system (ECCS) and containment isolation valves in FSAR Update Sections 6.2 and 6.3 was not completely accurate for DCPP. Not all these valves are double packed and fitted with stem leakoffs to the equipment drain system. What constitutes a full set of

packing is not defined at DCPP. Nor are packless valves always used where possible. Furthermore, at DCPP these valves are normally purposefully not backseated when opened, to help minimize stresses on the valves imposed by thermal transients. Finally, not all body-to-bonnet valve gaskets are asbestos since use of asbestos in the plant has been curtailed. The discussion of these considerations in the FSAR Update was revised to make it specific to DCPP.

Safety Evaluation Summary

These aspects of valve design and operation are all related to controlling their post-accident radioactive leakoff to be less than that assumed in the DCPP offsite dose analysis. At DCPP, assurance that post-accident radioactive leak rate to the environment would be less than that assumed in the offsite dose analysis is demonstrated by performance of surveillance test procedures that measure such leakage from the subject valves. In this manner, it is confirmed by test that the consequences of an accident would not be increased above that previously evaluated.

38. Insulation for CFCU Motor Leads and Connections
FSAR Update Section 6.2.2.3.3.2 (LBIE Log No. 98-055)

This change revises the FSAR Update with regard to the rating of the insulation for the containment fan cooler unit (CFCU) motor internal leads and terminal box-motor interconnections. The FSAR Update previously stated that the insulation rating met or exceeded the rating of the motor (2300 V). The insulation rating, however, only needs to meet or exceed the rating of the service voltage, which is 460 V. The FSAR Update was therefore changed to reflect this reduced voltage requirement by reference to a Westinghouse evaluation contained in a PG&E environmental qualification (EQ) file.

Safety Evaluation Summary

The CFCU motor internal leads and terminal box-motor interconnections only need to exceed the service conditions of the DCPP 480 V system (460 V +/- 10 percent at the motor terminals per Design Criteria Memorandum (DCM) S-64). The Westinghouse evaluation (WCAP-7829) is a part of EQ file 1H-05 and confirms that the use of 600 V cables are adequate to ensure the ability of the CFCUs to fulfill their post-accident function. Therefore, this change does not involve an unreviewed safety question.

39. Evaluation of Insulation Loss and Recirculation Sump Availability
FSAR Update Section 6.2.3.3.8 (LBIE Log No. 97-164)

The containment recirculation sump debris analysis was inconsistent with statements made in the FSAR Update. Specifically, the FSAR Update stated that all fiberglass insulation debris is assumed to be transported to the sump,

and the sump screen is designed to continue functioning without impeding water flow when it is 95 percent blocked. A new insulation debris methodology was developed, based on NUREG/CR-2791, which assumes less than 100 percent of the insulation debris reaches the sump, and utilizes a better criterion (differential pressure drop across the outer screen) for assessing the impact of sump screen blockage. Other conservative assumptions were made which made the new analysis, on the whole, more conservative than the previous analysis.

Safety Evaluation Summary

The containment recirculation sump debris analysis demonstrates that the screen remains operable with old and new methodologies under the worst-case loss-of-coolant accident conditions when both fiberglass and paint debris are deposited on the sump screen. This analysis shows that the sump screen and debris provide low enough flow resistance to ensure adequate flow to the residual heat removal (RHR) pumps, and to ensure that RHR pump net positive suction head is maintained during recirculation.

40. Changeover from Injection Mode to Recirculation After Loss of Primary Coolant
FSAR Update Section 6.3, Appendix 6.3A, and Associated Tables
(LBIE Log No. 97-024)

The FSAR Update was revised to reflect changed assumptions in residual heat removal pump and containment spray pump flows, and containment pressure during the changeover from injection to recirculation following a loss-of-coolant accident (LOCA). Included is a discussion of the single active failure during the changeover. The changes are due to a more accurate analysis using more conservative assumptions. There were no changes in the configuration of DCPP. These changes affected the time available for operator manual actions.

Safety Evaluation Summary

This safety evaluation defines the acceptance criterion for the evaluation of manual switchover to cold leg recirculation as the refueling water storage tank (RWST) volume margin. As stated in Supplement 9 to the Safety Evaluation Report (SSER), there is an implied margin of 32,500 gallons remaining in the RWST at the completion of the switchover to cold leg recirculation. Other design bases for switchover include maintaining sufficient net positive suction head (NPSH) for the emergency core cooling systems (ECCS) and completion of operator switchover actions in about 10 minutes.

The manner in which the ECCS and containment spray system are operated and sequenced during the changeover from the injection mode to the recirculation mode does not change the probability or consequences of any accident previously evaluated in the FSAR Update. Although the new analysis increased the flow rates for the residual heat removal (RHR) and containment spray (CS)

pumps, NPSH is not affected and the total time available for operator switchover continues to be greater than 10 minutes. The analysis shows that there are no increases in probability or consequences of a malfunction of equipment because there is no loss of NPSH which could interrupt continuous cooling flow to the core.

The revised analysis assumptions do not introduce a possible new malfunction of equipment because the flows remain within pump, piping, and instrument design bases. The changes do not introduce any new common mode failures. The safety evaluation specifically includes the analysis of a single failure of an RHR pump to trip automatically. The single failure had not been previously defined nor evaluated. The new switchover time available is still greater than the actual time to accomplish switchover, even under the worst case single failure assumption.

The margin of safety, as defined in the ECCS Technical Specifications (TS) Bases, 10 CFR 50.46, and 10 CFR 50, Appendix K, is not reduced. The available RWST inventory meets the safety analysis and the TS, even with the new, more accurate, instrument uncertainties. The RWST volume margin remaining at the completion of switchover is 37,450 gallons and is greater than the SSER 9 implied margin. Therefore, the margin of safety has not been reduced.

41. Pump Net Positive Suction Head
FSAR Update Section 6.3.2.14 and Table 6.3-11 (LBIE Log No. 96-017)

Revise FSAR Update Section 6.3.2.14 and Table 6.3-11 to capture the minimum sump water elevation static head above the sump flow elevation, as allowed by Regulatory Guide (RG) 1.1, and to increase the residual heat removal (RHR) pump maximum flow rate from 4,500 gpm to 4,900 gpm for the worst case assumption in the post loss-of-coolant accident (LOCA) alignment.

Safety Evaluation Summary

To increase RHR pump maximum flow rate from 4,500 gpm to 4,900 gpm, the required net positive suction head (NPSH) has been increased from 19.5 feet to 25 feet. By taking credit for the minimum water level above the sump floor, the available NPSH is 28 feet which is more than the required NPSHR of 25 feet. Increased RHR pump flow will not impact the post-LOCA emergency core cooling system (ECCS) performance because: (1) there will be more flow to the core to provide cooling, thus increasing conservatism, (2) it will not boost centrifugal charging pumps (CCPs) nor safety injection pumps (SIPs) beyond their runout limits since the boosted pressure from the RHR pump decreases as flow increases, (3) RHR pumps have been actually tested by the vendor to a flow beyond the 4,900 gpm limit, (4) the increased brake horsepower is within the

motor capability, and (5) NPSH margin exists. Therefore, it is acceptable to increase the RHR pump maximum flow rate from 4,500 gpm to 4,900 gpm.

42. Chemistry Environment for Environmental Qualification
FSAR Update Section 6.3.2.4 (LBIE Log No. 98-100)

This change removes the detailed description of the chemistry environment used for environmental qualification in Section 6.3.2.4 and references Section 3.11, where the environmental program is described with references to pertinent documents that contain the details of the chemistry environment used in the testing.

Safety Evaluation Summary

This FSAR Update revision only changes the location of the information about the chemistry of the spray solution used for environmental testing. Therefore, no unreviewed safety question is involved.

43. Digital Feedwater Control System Steam Flow Arbitrator
FSAR Update Section 7.2.2.3.5 (LBIE Log No. 98-048)

This change adds a description of the digital feedwater control system (DFWCS) steam flow arbitrator signal validation function to FSAR Update Section 7.2.2.3.5 based on a Westinghouse safety evaluation. The change shows how the DFWCS meets IEEE Standard 279.

Safety Evaluation Summary

The FSAR Update only discussed the median signal selector function of the DFWCS. The steam flow arbitration function is design basis information that should have been included in the FSAR Update when the DFWCS design change was made. Based on the Westinghouse evaluation contained in NSAL 96-04, the addition of this information was determined to not involve an unreviewed safety question.

44. Addition of Automatic Start on Degraded 4.16-kV Vital Bus Voltage
FSAR Update Section 7.4.1.2.3 (LBIE Log No. 97-153)

The FSAR Update description of automatic diesel generator (DG) start was corrected to add automatic start on degraded 4.16-kV vital bus voltage as well as on loss of offsite power, loss of 4.16-kV vital bus voltage and safety injection (SI). In addition, the description of manual DG controls was corrected to remove the incorrect statement that manual controls for DG starting and control were provided at the vital switchgear. No such controls are located on the 4.16-kV vital switchgear.

Safety Evaluation Summary

The FSAR Update change was made to correct information in the FSAR Update so that the system design and operation were correctly described. No changes were made to the facility or system operation. There was no impact on any accident or equipment analysis evaluation.

45. Discrepancy Between FSAR Update and Calculation IH-100 Rev 10/Plant Information Management System (PIMS) CDB
FSAR Update Section 7.5 and Table 7.5-6 (LBIE Log No. 97-091)

FSAR Update Section 7.5 and Table 7.5-6 contained incorrect instrument ranges for the containment recirculation sump water level (narrow range) and Containment Pressure (wide range). This evaluation addressed changing the range for the narrow range containment sump water level from “88.5 to 97 ft” to “88.5 to 96.6 ft” and changing the range for the wide range containment pressure from “0 to 200 psig” to “-5 to 200 psig.”

Safety Evaluation Summary

The range for the narrow range containment recirculation sump level was changed from “88.5 to 97 ft” to “88.5 to 96.6 ft.” This range should have been changed to “88.5 to 96.6 ft” as part of Design Change Package (DCP) J-41715, which identified the need to change the range statements in the FSAR Update. However, in revising the FSAR Update, the range was rounded from 96.6 ft. to 97 ft.

The range for the wide range containment pressure was changed from “0 to 200 psig” to “-5 to 200 psig.” This range change is in accordance with the original license commitment (see Supplement 14 to the Safety Evaluation Report) to have continuous indication of containment pressure over a range of -5 psig to three times the design pressure of containment for concrete or four times the design pressure for steel. The installed equipment has a range of -5 to 200 psig as was originally installed. Therefore, the FSAR Update is being revised to reflect the correct design of the wide range containment pressure.

46. Thermal and Hydroelectric Plants Underfrequency Setpoints
FSAR Update Section 8.2.2.2 (LBIE Log No. 98-110)

PG&E has revised the hydroelectric generating plant underfrequency setpoints based on the guidelines of the Western Systems Coordinating Council. A discussion of these guidelines and the broad capability of hydroelectric units to operate during underfrequency events has been added to the FSAR Update.

Safety Evaluation Summary

The purpose of the underfrequency setpoints is to provide security and protection of the interconnected bulk power network by arresting frequency decline during periods of insufficient generation. PG&E's load shedding program is intended to automatically shed about 50 percent of the load within its control area. The previously hydroelectric underfrequency setpoint was designed so that hydroelectric generation would be the last units on the grid to trip on underfrequency. This remains true for the revised setpoints. Therefore, changing the hydroelectric underfrequency setpoint does not affect accidents or equipment malfunctions evaluated in the FSAR Update. Based on these considerations, it was concluded that no unreviewed safety question is involved.

47. Diesel Generator Capability
FSAR Update Section 8.3 (LBIE Log No. 97-082)

This change was made to clarify transient voltage and frequency dip and recovery times during load sequencing to discuss previously established commitments with respect to emergency diesel generator (EDG) performance during load sequencing, to recognize that the KWS relays are not credited for performing a safety function, and to appliy Regulatory Guide (RG) 1.9, Rev. 2, "Regulatory Position C4," as it pertains to voltage and frequency dip and recovery during load sequencing,

Safety Evaluation Summary

DCPP meets the frequency and voltage dip requirements of RG 1.9, Revision 0, as demonstrated by analysis in DCPP Calculation 215-DC, Revision 2, for nominal load block time intervals. DCPP meets the frequency and voltage recovery requirements of RG 1.9, Revision 0, as demonstrated by analysis in Calculation 215-DC, Rev. 2 for nominal load block time intervals. DCPP meets commitments to the NRC in PG&E Letter DCL 85-132 for demonstrating that the objectives of RG 1.9 are met for worst case load block time intervals, as demonstrated by analysis in Calculation 215-DC, Revision 2, and preoperational testing.

48. Diesel Generator Frequency Dip and Recovery
FSAR Update Section 8.3.1 (LBIE Log No. 98-034)

FSAR Update Section 8.3.1.1.13, "Diesel Generator Units," has been revised to clarify transient voltage and frequency decrease and recovery times during load sequencing. Specifically, the revisions (1) apply the criteria of Regulatory Guide (RG) 1.9, Revision 2, "Regulatory Position C4," as it pertains to voltage and frequency dip and recovery during load sequencing, (2) documents previously established commitments to demonstrate emergency diesel generator (EDG) performance during load sequencing with worst-case sequence timing intervals,

and (3) explicitly states that the KWS relays are not credited for performing a safety function.

Safety Evaluation Summary

The evaluation performed shows that the EDGs (1) meet the frequency and voltage decrease requirements of RG 1.9, Revision 0, for nominal load block time intervals, (2) meet the frequency and voltage recovery requirements of RG 1.9, Revision 2, for nominal load block time intervals, and (3) meet commitments to the NRC for demonstrating that the objectives of RG 1.9 are met for worst-case load block time intervals. Additionally, analysis is referenced that demonstrates acceptable frequency recovery without crediting the KWS relays. Based on the results of the evaluation, it is concluded that no unreviewed safety question is involved.

49. Diesel Generator Starting Air Requirements
FSAR Update Section 8.3.1.1.13.2 (LBIE Log No. 97-053)

FSAR Update Section 8.3.1.1.13.2 is revised to clarify the statement “three (3) consecutive 15-second cranking cycles” as it relates to nominal sizing criteria for the air start receivers. This FSAR Update change revises the text to identify the “three (3) consecutive 15 second cranking cycles” as sizing criteria used by the vendor to size the air start receivers .

Safety Evaluation Summary

The emergency diesel generators (EDGs)) are not accident initiators. This change is not the result of any physical modification to the EDGs or related systems. The capability of the DEGs to perform their design function will not be adversely impacted by revision to the FSAR Update text to clarify the starting air receiver sizing criteria. The probability of occurrence of an accident, malfunction of equipment important to safety, radiological consequences of accidents evaluated, different type of accidents, or margin of safety previously evaluated in the FSAR Update will not be adversely impacted. Therefore, revising the FSAR Update text to clarify the EDG starting air receiver sizing criteria will not result in an unreviewed safety question.

50. FSAR Update Change Chapter 8.3.1.1.13.6
FSAR Update Section 8.3.1.1.13.6 (LBIE Log No. 97-162)

This section describes diesel generator engine trips. The change deletes the 4160-V bus differential from the list of trips.

Safety Evaluation Summary

The proposed revision modifies an existing section of the FSAR Update to correct an error. The 4160-V bus differential only trips the 4-kV breaker to the diesel generator. It does not trip the diesel generator. There is no safety significance to this change since there is already a failure that would disable the diesel from providing power to its load. The correction describes the as-built response to this failure.

51. Modes 5 and 6 Electrical Alignment
FSAR Update Section 8.3.1.4 (LBIE Log No. 97-057)

The change addressed the removal from FSAR Update Section 8.3.1.4, Independence of Redundant Systems [Class 1E Electrical Systems], of material describing contingency configurations for Mode 5 and 6 operation. This material was not incorrect, but it was an inappropriate level of detail, and it described sample configurations that may not be utilized.

Safety Evaluation Summary

There was no identified safety impact of removing the material. The described configurations are still allowed.

52. Deletion of Requirement for Cables Terminating on Separate Terminal Blocks
FSAR Update Section 8.3.1.4 (LBIE Log No. 98-003)

This FSAR Update change deletes the requirement that redundant cables terminate on separate terminal blocks. It properly characterizes that they "typically" are terminated on separate terminal bolts.

Safety Evaluation Summary

The design basis is that mutually redundant circuits be separated by 5 inches or a separation barrier. When mutually redundant circuits are terminated on the same terminal block, barriers are an acceptable means of providing separation and are provided up to the terminal block as required by Design Change Memorandum (DCM) T-19. The terminal block provides sufficient clearance and leakage distance to meet the requirements of a separation barrier. The barriers assure that the probability or consequence of an accident will not be increased.

53. Use of ICEA P-54-440 for Derating of Cable Installed in Cable Tray
FSAR Update Section 8.3.1.4.3 (LBIE Log No. 96-029)

The FSAR Update has been updated to reflect the use of Standard ICEA P-54-440, which is the industry recognized method for derating cables installed within cable tray. ICEA P-54-440 derates cable ampacity based upon percent fill.

Safety Evaluation Summary

Cable ampacity is not the source of an accident and does not impact the consequences of a malfunction of equipment. Cable derating is not related to creation of accidents or to the margin of safety. The probability of occurrence of a malfunction of equipment or the possibility of a malfunction of equipment important to safety will be decreased by the use of standard ICEA P-54-440.

54. Reactor Vessel Stud Detensioning
FSAR Update Section 9.1.4.2.1.13 (LBIE Log No. 98-014)

The FSAR Update is revised to eliminate reference to the number of reactor vessel stud tensioners required for tensioning and detensioning activities.

Safety Evaluation Summary

An engineering evaluation of reactor vessel stud tensioning and detensioning procedures has been performed and revised procedural guidance developed and implemented. As part of the revised procedure, detensioning may be accomplished with either six or three hydraulic tensioners, or with only two if one fails. The revised procedure has no effect on accidents analyzed in the FSAR Update. All ASME Code stress and fatigue limits will be met and there will be no effect on any other safety-related equipment. Therefore, it is concluded that the proposed change does not involve an unreviewed safety question.

55. Auxiliary Systems/Fuel Storage and Handling
FSAR Update Section 9.1.4.2.1.4 (LBIE Log No. 97-155)

The FSAR Update section was revised to remove a statement that the fuel handling building (FHB) crane is normally stored in the hot shop. The statement was not supported by any commitment or basis. The FHB crane is seismically qualified for its entire runway. Parking is not restricted. Removing the statement from the FSAR Update eliminated unnecessary movement of the FHB moveable seal walls, and allowed operations flexibility to store the crane to better support normal operations.

Safety Evaluation Summary

The only FHB crane accident evaluated in the FSAR Update is a load drop over irradiated fuel. The crane is seismically qualified for its entire runway. Travel over the spent fuel pool (SFP) is controlled by Technical Specification 3/4.9.7 and by plant procedures. The crane is not stored over the SFP. No new accidents are created by storing the crane in the FHB while not in use. Allowing the crane to remain in the FHB while not in use will not affect any accident analysis. Equipment required for safe shutdown is not affected because crane storage is limited to FHB areas that do not contain equipment important to safety.

56. Relief Valve Criteria
FSAR Update Section 9.2.2.2.9 (LBIE Log No. 97-052)

The change addressed was the removal from FSAR Update Section 9.2.2.2.9, component cooling water (CCW) system valves, of the paragraph which contains the following information: "The relief valve [RV-52] on the component cooling water piping downstream of the excess letdown heat exchanger is sized for a tube break in the heat exchanger …. The relief capacity of this valve is such that the design pressure of this portion of the CCWS will not be exceeded."

Existing DCPP calculation for this valve demonstrating capacity is an equilibrium calculation. Equilibrium assumptions like perfect mixing are not as conservative as a three-dimensional transient analysis would be. It would be difficult to perform an accurate two-phase, three-dimensional analysis, and it is believed that the results may indicate higher than design pressures.

Safety Evaluation Summary

The justification for removing the statement is that there is no need to design against a tube rupture in this heat exchanger. A tube rupture here is a non-credible event. These tube walls are relatively thick, the fracture analysis indicates that failures will be more likely to be axial cracks and double-ended rupture will not occur, and inservice time for these heat exchangers (HXs) is very low (typically these HXs are only used when mechanical troubles exist in the normal letdown HX path. Westinghouse discusses the non-credibility of a tube break in letter PGE-97-530. Not assuming a double ended rupture in these 5/8-in. tubes is consistent with NRC Standard Review Plan 3.6.1, Appendix B, which does not require assuming circumferential breaks in pipes of less than 1-in. diameter.

DCPP's excess letdown heat exchanger is similar to most Westinghouse designs and no other Westinghouse FSAR Update has been discovered with this design statement. It does not appear in RESAR-3 or the updated FSARs of Turkey Point, Vogtle, Shearon Harris, Salem, Sequoia, or Commanche Peak.

Therefore, removal of this statement makes the DCPP FSAR Update consistent with sister Westinghouse plants, and enables PG&E to avoid reliance on a calculation believed to be non-conservative.

Licensing material such as the Standard Review Plan and (Supplement to Safety Evaluation Reports (SSERs) were reviewed. There was no evidence discovered that would lead to the conclusion that the NRC relied upon this function of RV-52 to grant the DCPP Operating License.

57. Delete Reference to Flow Switch 22
FSAR Update Section 9.2.3.3 (LBIE Log No. 97-114)

All references to flow switches/alarms (FS-22) are deleted from Section 9.2.3.3. FS-22 is located in the main makeup water header from the raw water reservoirs into the fuel handling building/auxiliary building. It has been concluded that break flow would not be enough to actuate the FS-22. No fieldwork is planned - the switches are to remain installed but not maintained.

Safety Evaluation Summary

The probability of occurrence of an accident (flooding) does not increase by deleting the flow switches/alarms in Section 9.2.3.3. The auxiliary building sump's high level alarm is adequate to detect and mitigate flooding, therefore break detection and isolation can still be accomplished as before.

58. Liquid Sampling System FSAR Update Discrepancies
FSAR Update Section 9.3 and Table 9.3-2 (LBIE Log No. 97-072)

These changes are made to revise sample transit time, make an editorial change in the description of sample flow, and revise the number of sample heat exchanger and sample heat exchanger design information.

Safety Evaluation Summary

There is no safety impact because this change does not involve any physical change to the plant. The changes are being made to update the design data in the FSAR Update and to better reflect actual plant conditions. Therefore, there is no increase in probability or consequences of an accident and no reduction in margin of safety.

59. Testing of Floor and Equipment Drainage Systems
FSAR Update Section 9.3.3.4 (LBIE Log No. 98-099)

This change clarifies the monitoring and testing performed on the floor and equipment drainage system prior to and during plant operation. It states that the systems were tested and inspected prior to plant operation and are periodically monitored during plant operation.

Safety Evaluation Summary

The evaluation performed for this clarification concluded that no unreviewed safety question is involved.

60. Undampered Ventilation Duct Penetrations
FSAR Update Section 9.5.1 and Appendices 9.5A and 9.5B
(LBIE Log No. 97-139)

DCPP fire hazards Appendix R evaluation (FHARE) 33 evaluates the acceptability of having ventilation duct penetrations that do not have fire dampers and do meet the 3-hour rating definition for a fire barrier. Some of the undampered duct penetrations have been previously described to the NRC in the Unit 2 10 CFR 50, Appendix R, report. See Supplement 31 to the Safety Evaluation Report for approval of deviations.

FHARE 33 was revised to incorporate the current safe shutdown analysis (DCPP Calculation M-928) and to delete a ventilation duct penetration previously evaluated as undampered but where a fire damper was actually installed. With the addition of the sixth diesel generator (DG 2-3), the physical layout of the plant was changed along with the safe shutdown analysis due to new safe shutdown circuits. A new layout and fire area was added for DG 2-3. References and combustible loading description were revised to be consistent with the FSAR Update and the combustible loading calculation.

Safety Evaluation Summary

FHARE 33 evaluates an as-built condition against the effects of a postulated fire. No new fire hazards were introduced. Normal function of safety-related equipment was not affected. Fire protection features were not changed. Probability of a fire or of other accidents was not changed. The primary changes to FHARE 33 involved addition of a new fire area for the DG 2-3 room and incorporation of the safe shutdown analysis in Cal. M-928. The changes do not affect ability to achieve and maintain safe shutdown. FHARE 33 does not affect non-fire accidents evaluated in the FSAR Update.

61. Computer-Based Fire Alarm System
FSAR Update Section 9.5B (LBIE Log No. 98-029)

In response to NRC Open Item 275/87-27-02, DCPP committed to install a computer based fire alarm system capable of providing the features specified in National Fire Protection Association (NFPA) 72D. This new fire alarm system has back up power through an uninterruptible power supply or batteries that meets the requirements of NFPA 72D. As a result of this change, FSAR Update Section 9.5B is revised to clarify the sources of back up power for the fire detection and alarm panels

Safety Evaluation Summary

This change only clarifies the sources of back up power for the fire detection and alarm panels. There is no increased probability of an accident, no increased accident consequences, no increase in the probability of occurrence of malfunction of equipment and no increase in consequences due to equipment malfunction. No new type of accident is created and there is no reduction in the margin of safety as defined in the Technical Specifications.

62. Drainage to the Equipment Drain Tank and Auxiliary Building Sump
FSAR Update Sections 11.2.2.2 and 11.2.2.3 (LBIE Log No. 98-075)

This change corrects drainage inputs from equipment in the auxiliary building that are collected in the miscellaneous equipment drain tank and corrects sources of potentially contaminated auxiliary building floor drain wastes that are collected in the auxiliary building sump.

Safety Evaluation Summary

The changes to the FSAR Update involve the specific routing of wastes to closed and open drains to bring the document into conformance with the plant design. The total amount or processing of liquid waste is unaffected. None of the changes decrease confinement and most increase confinement. Potential accidents analyzed in the FSAR Update are unaffected. Therefore, it is concluded that no unreviewed safety question is involved.

63. General Reference to the DCPP Q-List
FSAR Update Sections 3.1 and 3.2 (LBIE Log No. 96-019)

The substance of these changes represents an enhancement of the presentation of the design bases and classification details for DCPP structures, systems, and components (SSCs). No physical or de facto changes were made to the plant; no analyses or analysis assumptions or inputs were revised; no SSC classifications were changed; DCPP compliance with the general design criteria (GDC) remains unchanged; control of the DCPP design basis is maintained.

Safety Evaluation Summary

Previously-evaluated accidents and malfunctions probabilities and dose consequences are unaffected, no new or different types of such events are created or become credible, and no interface with the technical specifications or their bases results from these changes.

64. Factors of Safety for Structure Gaps and Raceway Flexibility
FSAR Update Sections 3.8.1.5.3 and 3.10.2.18 and Table 3.8-5B (LBIE Log No. 98-108)

The FSAR Update changes evaluated are necessary to account for the dimensions of existing gaps between interior and exterior surfaces of the containment structure determined during walkdowns. The specific changes involve revision of the FSAR Update to account for revised factor of safety calculations that consider relative seismic displacements. Also, the FSAR Update section on electric cable raceways is revised to show that the effects of differential displacements on raceways spanning between structures can be accommodated through either use of flexible joints or through the flexibility of the raceway and its supports.

Safety Evaluation Summary

The existing gaps in the containment annulus and between the containment structure and the auxiliary building have been compared with calculated seismic displacements at several elevations. Factors of safety against contact have been determined and found to be adequate. Evaluations have also been performed to ensure that electric raceways between structures can withstand structural shifts due to seismic effects without damage. Based on a detailed consideration of each of the 10 CFR 50.59 questions, it has been determined that the seismic gap issues do not involve an unreviewed safety question.

65. Reactor Coolant System FSAR Update Discrepancies
FSAR Update Sections 5.1, 5.2, 5.4, and 5.5 (LBIE Log No. 97-069)

The changes are made to clarify the content of the FSAR Update and better describe the system design and operation. Also, changes are made to correctly describe the actual inspection performed. No physical changes are being made to the plant due to this FSAR Update change. The changes are made to more precisely describe system and the inspection of various components. No commitment or required inspection is being removed.

Safety Evaluation Summary

There is no increase in probability or consequence of an accident and no reduction in margin of safety. Therefore, it is concluded that no unreviewed safety question is involved.

66. Residual Heat Removal System FSAR Update Discrepancies
FSAR Update Sections 5.2, 5.5, 5.6, Tables 5.2-10 and 5.2-22 (LBIE Log No. 97-070)

The changes are made to precisely describe the content of the FSAR Update, to reflect the actual setpoint of the low-pressure alarm (pressurizer relief valve interlock), and to remove some unnecessary information to reflect the as-installed condition.

Safety Evaluation Summary

No safety impact exists because this FSAR Update change notice does not involve any physical change to the plant. The changes are being made to more precisely describe system and the inspection of various component. No commitment or safety function of the affected equipment is being changed. Therefore, there is no increase in probability or consequences of an accident or any reduction in margin of safety.

67. Reactor Vessel Fluence Calculations
FSAR Update Sections 5.2.4.4.4 and 5.2.4.4.5 (LBIE Log No. 97-177)

FSAR Update Sections 5.2.4.4.4 and 5.2.4.4.5 are revised to reflect the current methodology used by industry for performing reactor vessel fluence calculations. The methodology change incorporates more modern and accurate methods, new neutron transport computer programs and cross section database, has been reviewed and approved by NRC (WCAP -14040-NP-A), and is consistent with Draft Regulatory Guide DG-1025, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.”

Safety Evaluation Summary

This change to the methodology for calculating reactor vessel fluence has been benchmarked, and reviewed and approved by NRC (WCAP-14040-NP-A). While the updated fluence methodology could affect calculation of reactor pressure vessel (RPV) fracture toughness, inadequate fracture toughness leading to a postulated failure of the RPV is outside the plant design basis. Fracture toughness requirements are ensured through the federal regulations (10 CFR 50.60, 10 CFR 50.61, and 10 CFR 50, Appendix G, in combination with monitoring programs required by 10 CFR 50, Appendix H). This change in fluence methodology has no impact on the existing fracture toughness limits, or

the margin prescribed to these limits (which account for uncertainties in vessel fluence measurements and methodology), or the methods for calculating RPV fracture toughness (ASME B&PV Code Sections III and XI, Appendix G, and 10 CFR 50, Appendix G).

68. Reactor Coolant System FSAR Update Discrepancies
FSAR Update Sections 5.5, 5.6, Tables 5.2-9, 5.2-16, and 5.5-16 (LBIE Log No. 97-071)

The changes are made to: (1) more precisely describe the reactor coolant system (RCS), (2) delete redundant information, and (3) reflect the actual installed equipment.

Safety Evaluation Summary

No safety impact because this FSAR Update change notice does not involve any physical modification to the plant and the design and/or function of the RCS has not been changed.

69. Valve Leakage Criteria
FSAR Update Sections 6.2 and 6.3, Tables 6.3-1 and 6.3-3 (LBIE Log No. 97-133)

The FSAR Update is updated to clarify that the valve leakage criteria listed in Section 6.2.4.2.2 and Table 6.3-1 are those used for initial valve purchase, and not used for maintenance/in-service testing, and that the specific valves requiring a specific leak rate are covered by Technical Specification required surveillance testing programs.

Table 6.3-3 was updated to reflect that valves may have corrosion resistant bolting in addition to the listed low alloy bolting.

Safety Evaluation Summary

This change to the FSAR Update is a clarification to the text/table which does not affect the operation of the facility. The affected emergency core cooling system (ECCS)/containment isolation valves cannot cause any evaluated accident. The consequences of an accident are not increased as the valves in question perform their safety function unchanged in any manner. All valves in which leakage is a safety requirement remain tested per Technical Specification requirements.

70. Sodium-Hydroxide Additive Tank (SAT) Low-Level Alarm Function
FSAR Update Sections 6.2.3.4.2.1 & 6.2.3.5.3 (LBIE Log No. 98-004)

The change to FSAR Update Section 6.2.3.5.3 is a change to an incorrect description of the function of the SAT low-level alarm described in the FSAR Update. The SAT level instrumentation is not safety- related and is set to alarm just above the minimum required Technical Specification level. Operator action is required to investigate the cause of the low level alarm and to increase SAT inventory to within its normal operating band. No operator action is required when the SAT inventory is depleted during a loss-of-coolant accident (LOCA), and therefore no alarm is provided for this function.

Safety Evaluation Summary

The low level alarm provides early warning to operators to ensure that minimum SAT inventory is available pursuant to Technical Specification requirements.

During an accident, when the SAT is depleted, it would have performed its safety function of providing pH control for iodine removal by the containment spray. Under certain LOCA scenarios, it is possible for the SAT to be depleted before emergency core cooling system (ECCS) injection phase is completed (refueling water storage tank (RWST) at low-low level). This would allow nitrogen from the SAT to be ingested into the containment spray system (CSS) pumps near the end of the ECCS injection phase until the CSS pumps are shut off. An evaluation was performed indicating that the amount of nitrogen ingestion does not affect the CSS pumps from performing their containment spray function and transferring the RWST contents into the containment. The CSS pumps are not required for accident mitigation after completion of the injection phase of ECCS and the CSS pumps are shut off.

71. Clarification of Load Rejection Capabilities
FSAR Update Sections 7.7.1.8 and 10.4.4.1 and Table 1.3-1 (LBIE Log No. 97-149)

Prior to this change, the context of the referenced FSAR Update sections stated that the reactor would not trip following a 100 percent load loss. The DCPP turbine bypass system was designed to accommodate a load rejection above 50 percent power without a reactor or turbine trip. However, due to the large number of systems that must operate precisely in a fully coordinated manner, a manual or automatic reactor trip may follow a large load rejection. In fact, there has been only one occasion where a full load rejection has not resulted in a reactor trip.

Safety Evaluation Summary

The FSAR Update change was made to better describe the plant response following a large load rejection event. It was not made because of any plant equipment modification or a change in the way the plant was operated. No new or different accidents or malfunctions were introduced. There was no change

that could affect the cause of a load rejection event. Therefore, the probability of a load rejection event, either with or without a reactor trip, is not affected.

The FSAR Update change clarifies the response of the plant to most load rejection events. The plant was designed to accommodate a full load rejection event without a reactor or turbine trip, and this design was not changed. FSAR Update Section 15.2.7 evaluated full load rejection events both with and without reactor trip. Consequences of a load rejection event are not increased whether or not the reactor trips.

The change implies a potential decrease in load rejection events without reactor trip, and a corresponding increase in load rejection events with reactor trip. Such an increased reactor trip frequency could affect the plant's cyclic or transient design. Technical Specification Table 5.7-1 reactor trip system cyclic limits were not approached or exceeded when the current reactor trip rates were extrapolated for the remaining life of each DCPP unit. There is no effect on probability of an evaluated equipment malfunction.

72. Sale of MBPP and Establishment of the Independent System Operator (ISO)
FSAR Update Sections 8.1, 8.2 and 8.3 (LBIE Log No. 97-191)

Changes to FSAR Update Sections 8.1, 8.2 and 8.3 were made to reflect 230-kV system operation without the Morro Bay Power Plant (MBPP) and the addition of capacitor banks at DCPP. The changes also address the transfer of the 230-kV and 500-kV transmission system control from PG&E to the ISO.

This change also addresses the voltage improvements in the plant buses achieved through the installation of new startup transformers with automatic load tap changing feature. The new startup transformers are designed to maintain a preset voltage at the plant buses regardless of the 230-kV system voltage variations.

Safety Evaluation Summary

DCPP meets the design basis requirements for offsite power availability according to the commitments to 1971 general design criteria (GDC) 17, Regulatory Guides 1.6 and 1.32, and IEEE 308.

The offsite power remains reliable since the ISO is required to operate the grid in a reliable manner and maintain sufficient capacity and voltage to assure that safety loads are operable when powered from offsite power. The ISO has commited to comply with the requirements of Operating Instruction O-23. Operating Instruction O-23 provides minimum 230-kV voltage requirements to maintain DCPP operability with and without shunt capactors and no MBPP generation. This change does not result in a change of operation, maintenance,

physical change, or procedural change that would affect the probability or consequence of an accident.

73. HVAC System Changes
FSAR Update Sections 9.4 and 12.2 (LBIE Log No. 96-012)

Miscellaneous changes were made to the wording of the FSAR Update description and discussion of the DCPP heating, ventilating, and air conditioning (HVAC) systems.

Safety Evaluation Summary

A few of the changes were to more accurately reflect the actual configuration, function, or operation of HVAC systems, but have no affect on, or relation to, the safe operation of the plant or the system's ability to mitigate an accident or the probability of equipment malfunction. The nature of these wording changes to increase the accuracy of the FSAR Update is such that none of them has any effect on the probability of an accident occurring, on the consequences of an accident, on the probability or consequences of equipment malfunction, or on margin of safety.

74. FHB Ventilation Flow and Control Room Heat Load
FSAR Update Sections 9.4.4 and 9.4.5 (LBIE Log No. 98-094)

The changes involve updating the flow quantities of the fuel handling building (FHB) ventilation system and the control room (CR) heat load, as well as numerous editorial corrections.

Safety Evaluation Summary

The FHB ventilation system is designed to help mitigate a fuel handling accident in the FHB. The total as-built exhaust flows are the same for both units, but the branch flows are different. The Chapter 15 accident analysis is based on total flow, so branch flow has no impact on analysis results.

The design heat load for the control room was used to size the air conditioning equipment. Ample margin exists so that changes in calculated heat load, including accident conditions, can be accommodated. In both cases, it is concluded that the updating of FHB ventilation flow and CR heat load do not involve an unreviewed safety question.

75. Clarification of Procedure Enhancement Documentation
FSAR Update Table 17.1-1 (LBIE Log No. 98-027)

A clarification is added to the exceptions related to quality assure program requirements to explain the administrative control used to provide procedure enhancements feedback to the procedure sponsor.

Safety Evaluation Summary

The change deals with clarification of an administrative control regarding tracking of procedural enhancements and has no bearing on accidents evaluated in the FSAR Update. Therefore, it is concluded that no unreviewed safety question is involved.

76. Clarifications to the List of Active Valves
FSAR Update Table 3.9-9, Rev. 11A (LBIE Log No. 97-147)

The list of active valves in FSAR Update Table 3.9-9 contains valves that have a design basis active safety function to support accident mitigation and achieve safe shutdown, and also contains valves that have a nonsafety-related licensing basis active function to support achieving cold shutdown following a Hosgri earthquake. The distinction between these two classifications of valves has been made in other design basis documents outside the FSAR Update, but has not been made in this FSAR Update table. In addition, as iterated in the Diablo Canyon Supplement 7 to the Safety Evaluation Report (SSER) and SSER 22, DCPP is a “hot shutdown” plant, meaning that following an accident, “safe shutdown” is considered to be Mode 3. However, DCPP is required to be capable of achieving cold shutdown following a Hosgri earthquake or 10 CFR 50,Appendix R, fire with no concurrent accident. Again, while this distinction between the design basis safe shutdown and licensing basis shutdown definitions has been made in other design and licensing basis documents, it is not readily apparent in the FSAR Update. To clarify these two distinctions in the FSAR Update, two notes were added to the list of active valves in Table 3.9-9 that explain the distinctions.

Safety Evaluation Summary

While this constitutes a change to the FSAR Update, thus requiring a 50.59 safety evaluation, it is for clarification only, and does not constitute a change to the DCPP design or licensing basis. There is no change in the Code or quality classification, quality assurance, maintenance, or surveillance testing of any of the listed valves resulting from adding this additional clarifying information. The operability, dependability, and behavior of the valves is unchanged, and hence the consequences of an accident are unchanged.

77. CCW Train Separation Valve Designation
FSAR Update Table 3.9-9 (LBIE Log No. 97-063)

The component cooling water (CCW) system is normally operated with its two safety-related trains cross-connected. Since a passive failure of one of the trains is postulated after 24 hours after a loss-of-coolant accident (LOCA) has occurred, the system is designed to allow separation of the trains using manually operated valves. The valves used to accomplish this train separation are considered to be active valves and are listed in the FSAR Update Table 3.9-9 list of active valves. The configuration of the system is such that the trains could be separated in several ways, using different combinations of manual valves. Table 3.9-9 was revised to list the valves actually used by procedure to perform the train separation.

Safety Evaluation Summary

All the valves involved have the same Code classifications and level of maintenance and testing, and are equivalently capable of achieving the train separation. Hence there is no change in the potential consequences of an accident because there is no change in the ability to achieve CCW train separation using the equivalent set of valves indicated in the Emergency Operating Procedure when compared with using the set originally listed in the FSAR Update.

78. Reactor Coolant Pressure Boundary (RCPB) Leakage Detection Systems
FSAR Update Table 5.2-16 (LBIE Log No. 98-089)

This change revises Table 5.2-16 to correct typographical errors, clarify ranges of instruments, restate the way containment condensation liquid detectors respond, and updates the approximate time needed to detect a 1-gpm leak for each detector.

Safety Evaluation Summary

The proposed changes in FSAR Update Table 5.2-16 do not affect the function of the reactor coolant pressure boundary (RCPB) leakage detection systems, do not degrade the ability of the plant to detect a reactor coolant system (RCS) leak, and do not impact any assumptions made in evaluating the radiological consequences of accidents. There is no change in equipment reliability and no impact on fission product barriers. The changes simply bring the FSAR Update into agreement with the plant design licensed by the NRC and therefore do not create the possibility of an unreviewed safety question.

79. Administrative Control of Containment Isolation Valves 8823, 8824, 8843, and 8885A/B
FSAR Update Table 6.2-39 (LBIE Log No. 97-213)

This change updates Table 6.2-39 to show that the administratively controlled Containment Isolation Valves 8823, 8824, 8843, and 8885A/B do not have active

control room position indication while they are administratively cleared, i.e., the control room indicating lights do not function.

Safety Evaluation Summary

The changes are FSAR Update clarifications that do not affect operation of the plant or the results of any accident analyses. Therefore, no unreviewed safety question exists.

80. Post-Accident Monitoring Indicators
FSAR Update Table 7.5-4 (LBIE Log No. 98-088)

This change corrects a typographical error and deletes “indicator” from the plant vent monitor as low as reasonably achievable (ALARA) since only a recorder exists for this variable.

Safety Evaluation Summary

The plant vent monitor ALARA is a Regulatory Guide 1.97, Category 3, variable for which only a recorder is needed. This change is a document change only and involves no physical work The change is within the licensing basis and does not involve an unreviewed safety question.

81. Emergency Diesel Generator (EDG) Stop Button Loads for Battery 13
FSAR Update Table 8.3-11 (LBIE Log No. 98-091)

The power supply to the emergency diesel generator (EDG) emergency stop buttons was deleted and the buttons were wired directly to the shutdown lockout relays. The buttons are therefore no longer a load for Battery 13 and the FSAR Update was revised accordingly.

Safety Evaluation Summary

Modification of the stop button circuit is a design improvement that enhances reliability. The licensing basis is unattended; hence, no unreviewed safety question is involved.

82. Control Room Indicator Accuracy and Range Statements
FSAR Update Tables 7.5-1 Through 7.5-5 (LBIE Log No. 97-038)

There were several instances of inconsistent information concerning control room indication accuracy and range statements in FSAR Update Tables 7.5-1 through 7.5-5 as compared to the design calculations, supporting documents and as-built design. These changes were reviewed by all affected DCPP departments.

Safety Evaluation Summary

Many of the accuracy statements in FSAR Update Tables 7.5-1 to 7.5-5 are more conservative than what has been computed in design and supporting calculations. The proposed changes to the FSAR Update are intended to report the current and the correct status of the plant. The collective coordination related to this FSAR Update change request with the appropriate departments and groups ensures the consideration of control room indication accuracy in the plant activities are consistent with the plant design parameters. Therefore, there is no increase in the probability or consequences and no reduction in margin of safety.

83. Boric Acid Heat Tracing and Tank Heater Loads
FSAR Update Tables 8.3-3, 8.3-5, 8.3-6, and 8.3-7 (LBIE Log No. 97-214)

FSAR Update tables were revised to account for a reduction of electric heat tracing and tank heater loads of the boric acid system. The heater loads were previously assumed to be operating at 100 percent rated capacity. Since the heaters are temperature controlled and operate intermittently, their loading was reduced to 50 percent.

Safety Evaluation Summary

Reducing the heat tracing and tank heater loads of the boric acid system, which is not safety related, makes the FSAR Update consistent with plant operation. The margin of safety is not reduced and it concluded that this change does not involve an unreviewed safety question.

G. Other Changes

1. Reclassification of Containment Spray in the Recirculation Mode of Emergency Core Cooling to Nonsafety-Related
(Units 1 & 2) (LBIE Log No. 97-206)

This evaluation justified the reclassification of the containment spray system to nonsafety-related during the recirculation mode of a loss-of-coolant accident (LOCA), thereby eliminating the requirement that the containment spray system be functional during recirculation.

Safety Evaluation Summary

The safety evaluation concluded that the reclassification is justified since containment spray is only required to be in service during the injection phase of an accident, and not during the recirculation phase of an accident.

Note, however, that during the NRC architect-engineer inspection conducted in August and September 1997, the inspection team indicated that PG&E's decision to declassify the containment spray function during the recirculation phase of a LOCA was a potential unreviewed safety question (USQ).

In order to resolve this disagreement regarding the USQ, PG&E has submitted LAR 98-03 to change Technical Specification 3/4..6.2.1, "Containment Spray System," to clarify that containment spray is not required to be actuated during recirculation, but may be actuated at the discretion of the Technical Support Center.

2. Outage Safety Plan Schedule Change 1R8-05: Backseating of RCP 1-4 in Mode 5
(Units 1 & 2) (LBIE Log No. 97-115)

Reactor coolant pump (RCP) 14 will be backseated to work on the seal package. The Outage Safety Plan and schedule requires the RCPs to be coupled when the reactor coolant system (RCS) is intact. The reason is that, upon loss of residual heat removal (RHR), the RCS will eventually pressurize, lfting the RCP off the backseat, which would result in a small cold leg opening. A cold leg opening would lead to an inventory loss, which could eventually lead to core uncovery.

Safety Evaluation Summary

The Outage Safety Plan is not described in the FSAR Update. Additionally, maintenance of the RCP seals is not covered in the FSAR Update. This condition/configuration will not affect the safe operation of the plant. A contingency is provided to maintain the backseated condition of RCP 1-4 in order

to maintain RCS integrity to the low temperature overpressure protection (LTOP) pressure-operated relief valve (PORV) lift point. This will allow for core coolng to occur per normal shutdown operation scenarios. This contingency consists of one 20-ton hydraulic jack between the pump and motor shafts. This contingency can be installed within a very short duration relative to the time to boil.

3. Use of RM-87 as an Alternate to RM-29 in Emergency Plan (Units 1 & 2) (LBIE Log No. 96-039)

This licensing basis impact evaluation (LBIE) was prepared for Plant Staff Review Committee approval to formally allow RM-14/87 to be recognized and used as an alternative to RM-29 in the Emergency Plan for monitoring the plant vent effluent variable. The emergency action level classification chart in Emergency Procedure (EP) G-1 states that an unusual event must be declared if both the safety parameter display system and RM-29 lost all display capabilities. Since RM-14/87 has the same instrument classifications and covers a wider instrument range with better accuracy, it should be considered an alternate to RM-29, therefore, preventing unnecessary emergency declarations if RM-29 and SPDS were not available.

Safety Evaluation Summary

The LBIE covered a 50.59 review and a 10 CFR 50.54(q). Since no change to the facility or operation was proposed, and the RM-14/87 monitors met the requirements of the existing RM-29, the 50.59 did not reveal any unreviewed safety question issues. The 50.54(q) determined that the clarification in EP G-1 and Surveillance Test Procedure (STP) G-16 to also use RM-14/87 still meets the intent of NUREG-0654, 10 CFR 50.47(b)(4) and 10 CFR 50, Appendix E because it does not alter the emergency classification or condition but adds an additional method of performing the function.

4. Undampered Ventilation Opening in the Unit-2 Auxiliary Feedwater Pump Rooms FHARE 10, Rev. 3 (Unit 2) (LBIE Log No. 98-071)

This fire hazards Appendix R evaluation (FHARE) revision addresses a previously unevaluated seismic support strut penetration through a ventilation damper between the two auxiliary feedwater pump rooms. This Appendix R fire barrier is rated as a 1-hour barrier. The subject penetration is sealed with an untested 4-in. thick configuration consisting of fire resistant materials of calcium silicate board and silicone foam sealant around the 3-1/2-in. diameter schedule 80 steel pipe strut.

Safety Evaluation Summary

The maximum equivalent fire duration in either fire area/zone on each side of the barrier is 20 minutes, a low fire severity; there are no combustible materials in

the vicinity of the strut on either side of the barrier. Detection and automatic suppression features exist on both sides of the barrier. In the unlikely event of a fire affecting the fire area/zone on both sides of the barrier, the consequences would not be different from those evaluated and found acceptable in the FSAR Update.

5. Requirements for Non-Class IE Containment Overcurrent Protection
QE 10011535 (Units 1 & 2) (LBIE Log No. 97-098)

Supplementary Safety Evaluation 8 (SSER 8), dated November 15, 1978, required that primary and backup non-Class 1E penetration overcurrent protection be capable of remaining operable during an operating basis earthquake (OBE). The safety evaluation is to demonstrate that the existing documentation and analyses are sufficient to meet the intent of the SSER 8 requirements to protect the penetrations in the event of an OBE.

Safety Evaluation Summary

There is no licensing basis accident in Chapter 15 of the FSAR Update that postulates an accident during or after a seismic event. Seismic qualification of the reactor coolant pressure boundary precludes a loss-of-coolant accident occurring as a result of a seismic event. Redundant overcurrent protection assures that containment integrity is maintained and the single failure criterion is met during an accident. A failure modes and effects analysis demonstrates that there are no credible failure modes that would result in a failure to protect the penetrations for a fault inside containment after an OBE. The radiological consequences of analyzed events requiring containment integrity are not increased. There are no new accidents or increased consequences of malfunctions of equipment important to safety. There is no impact on the Technical Specifications or their Bases.

6. Unqualified Penetration Seals in the ASW Pump Room Barriers
FHARE 114 (LBIE Log No. 97-044)

Fire hazards Appendix R evaluation (FHARE) 114 evaluates the ability of the unqualified penetration seals in the auxiliary saltwater (ASW) pump room barriers to protect one train of safe shutdown circuits from the effects of a fire. FSAR Update Appendix 9.5A has been revised accordingly to address the non-rated seals.

Safety Evaluation Summary

The non-rated seals are installed in a configuration that is not supported by a qualified fire test. Therefore, a fire rating cannot be assigned to these configurations. In accordance with the fire hazards analysis in Appendix 9.5A of the FSAR Update, the ASW pump vaults are separated from other fire areas by

a 3-hour-rated fire barrier. FHARE 114 concludes that the effectiveness of the barrier is not reduced by the use of the non-rated seals. Therefore, no unreviewed safety question is involved.

7. CCW Heat Exchanger Rooms - Fire Area Boundary
FHARE 120, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-042)

This fire hazards Appendix R evaluation (FHARE) evaluates the acceptability of combining Fire Areas 14-E (component cooling water (CCW) Heat Exchanger Room) and 14-A (Main Turbine Building) in Unit 1 and combining the equivalent Unit 2 areas 19-E and 19-A. This would result in the existing barrier between the two areas no longer being controlled as an Appendix R barrier.

Safety Evaluation Summary

A review of the safe shutdown capabilities associated with these fire areas shows that there are no safe shutdown features in the CCW Heat Exchanger Room that are redundant to those in the Main Turbine Building, and vice versa. The ability to achieve and maintain safe shutdown will not be affected by this combining of areas. By combining these two areas in each unit, there is no intention to change the existing combustible loading in either area (which is already low), nor to change the existing fire detection and suppression features in either area, nor to reduce the effectiveness of the existing barrier between the two present areas.

8. Pipe Penetration Seals Through Plaster Walls in the Unit 1 AFW Pump Rooms
FHARE 121, Rev. 0 (Unit 1) (LBIE Log No. 98-073)

Numerous (~45) penetrations exist in three of the Appendix R fire barriers through plaster walls of the auxiliary feedwater pump rooms. These penetrations are located in the 1- and 2-hour rated sections of the fire barriers. The details of these penetrations are very similar to a tested configuration; but, not being identical, they are considered as untested, requiring a fire hazards Appendix R evaluation (FHARE).

Safety Evaluation Summary

The combustible loading in the related fire areas results in a maximum equivalent fire duration of much less than 1 hour, the largest being 19 minutes, The similarities of the design of these penetrations to the tested 3-hour configuration provides a level of protection easily commensurate with these low fire severities. In addition, detection and suppression equipment exists to respond to postulated fires. The FHARE evaluation of safe shutdown capabilities confirms that safe shutdown can be achieved and maintained in the event of a postulated fire.

9. Unsealed Penetrations With Fusible Link Chain Penetrants Through Fire Barriers
FHARE 123, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-039)

Small diameter (typically 3/4-in. or less), unsealed penetrations exist at various locations in DCPP, 3-hour rated, Appendix R fire barriers. These holes have fusible-linked chains passing through them associated with the fire-caused closure of roll-up fire doors. Free movement of the chain through the hole is required for the fire door actuation to occur. The wall thickness at the location of these penetrations is 10-in. minimum. They are typically high on a wall, near the top of the associated fire door.

Safety Evaluation Summary

These penetrations were provided to meet the requirements of NFPA-80, "Standard for Fire Doors and Fire Windows." For DCPP, Figure B-48 illustrates such installations. The small diameter of the hole and substantial thickness of the wall will limit the quantity of combustion products that will pass through the fire barrier while preventing flames from passing through the opening. This limited quantity of heated gasses is not expected to be great enough to raise the general area temperature or affect the operation of equipment in the unexposed compartment.

10. Unsealed Penetrations Through Barrier 119
FHARE 124, Rev. 0 (Unit 1) (LBIE Log No. 98-040)

Two unsealed penetrations exist in the CCW Pump 1-3 room floor, a 3-hour rated Appendix R fire barrier. The steel sleeves in the penetrations extend 4-in. above the floor level. The fire hazards Appendix R evaluation (FHARE) evaluates this condition between Fire Zone 3-J-3 above and fire Zone 3-C below.

Safety Evaluation Summary

Supplemental Safety Evaluation Report (SSER) 23 previously accepted the use of curbing around floor openings as contributing to the prevention of fire spread from flammable liquids. These two sleeved penetration configurations are consistent with the justification/reasoning given in SSER 23: the 4-in. high sleeves will prevent the flow of combustible liquid (lube oil) from the CCW pump area to the zone below. The total combustible loading in both the upper and lower areas is low (i.e., equivalent fire severity of less than or equal to 15 minutes). Fire detection and suppression systems exist in both zones. There is no redundant safe shutdown equipment in the two fire zones associated with these penetrations. A fire originating in the lower area is no more likely to compromise safe shutdown functions in the CCW pump room above, especially since a fire in the lower zone can only subject one of the penetrations to a fire since there is a wall between the two penetrations below the floor.

11. Lesser-Rated Plaster Blockouts and Penetration Seal Configurations
FHARE 125, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-041)

The fire barrier between each Unit's turbine-driven auxiliary feedwater pump room and the liquid holdup tank (LHUT) room is an Appendix R, 3-hour rated barrier. An approximately 2½ by 5 foot opening exists in each of these barriers; the opening is sealed with a 2-hour rated gypsum plaster seal assembly.

Safety Evaluation Summary

The LHUT area has manual suppression equipment and a combustible loading with an equivalent fire duration of only ½ minute; each pump room has area-wide detection and suppression equipment and a fire loading with an equivalent fire duration of less than 20 minutes. In the unlikely event a fire breached the subject boundary, safe shut down would not be compromised since no redundant safe shutdown components exist in the adjacent areas.

12. HVAC Ducts Through Modified Unrated Hatches
FHARE 126 (Units 1 & 2) (LBIE Log No. 98-101)

The 3-hour rated, Appendix R floor of each Unit's Cable Spreading Room (CSR) contains an equipment hatchway which is closed by the use of 1-in. steel hatch covers. This is an unrated configuration that was approved as a deviation in Supplemental Safety Evaluation Report (SSER) 23 (pages 9-18, -19, -31 and -32). A portion of the hatchway is now occupied by three heating, ventilating, and air conditioning ducts which penetrate vertically through this area. The ducts contain rated fire dampers but the exteriors of the ducts, though enclosed with heavy gauge angle steel at the penetration, are not sealed using a rated configuration.

Safety Evaluation Summary

The replacement of one of the hatch cover sections with the fire-dampered ducting does not change the basic fire barrier configuration. The discussions, evaluations, and conclusions in the original SER are still valid for this revised condition: the lower area is of low fire severity and contains smoke detection leading to an early manual response for suppression; though the upper area has a higher equivalent fire duration, it contains heat and smoke detection and an automatic CO_2 suppression system; smoke and hot gases from a fire in the upper area would rise away from the floor penetration preventing combustion products from moving into the area below. Though both fire areas contain safe shutdown circuits, shutdown capability remains intact should a fire in either area occur, due to redundant circuits and/or manual actions for mitigation.

13. Non-Rated Pipe Penetrations in Ceiling of Unit 1 Turbine-Driven Auxiliary Feedwater Pump Room
FHARE 128, Rev. 0 (Unit 1) (LBIE Log No. 98-049)

A 3-hour rated ceiling exists for the turbine-driven auxiliary feedwater pump room. The firewater pump room is located above this area. Firewater piping (8-in.) passes through 12-in. diameter sleeved penetrations in this ceiling at two locations. A pipe anchor constructed with 3/8-in. steel plate is built directly above each sleeved opening, completely sealing the top of each penetration.

Safety Evaluation Summary

Since the pipe anchor completely seals the penetration, smoke, hot gases, combustible liquids, and fire suppression water is prevented from passing through the barrier. The maximum equivalent fire duration for the two, adjacent areas is 19 minutes; the combustibles are not near to the penetrations. Each area has fire detection and suppression equipment. No safe shutdown redundancy exists between the two areas.

14. Duct Penetrations Through Common Walls Associated With Fire Zones 8-A, 8-D, 8-E, 8-F, 8-G, and 8-H
FHARE 129, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-035)

A return air duct within each unit's half of the control room passes through two Appendix R fire barriers without fire dampers installed within the plane of the barriers and without the required fire resistance of the ducting.

Safety Evaluation Summary

The subject, 16-gauge ducts are well-fitted to the wall penetrations with fire stops and are seismically supported. The fire hazards in the adjacent areas are limited (i.e., maximum equivalent fire duration of 50 minutes) such that the 3-hour rating is regarded as conservative for the existing hazards. Per the NFPA Fire Protection Handbook, ducting of this construction can be credited for fires of up to 1 hour equivalent duration. Detection and suppression equipment is located in or immediately adjacent to these control room fire areas. Since the control room is continuously occupied, any fire originating in these areas will be quickly detected and suppressed by plant personnel.

15. Unique Blockout Penetration Seal Through Barrier Between the Unit 2 Turbine Building and Containment Penetration Area
FHARE 13, Rev. 3 (Unit 2) (LBIE Log No. 98-051)

Two, 28-in. diameter main steam lines pass through a 3-hour rated wall between the containment penetration area and the turbine building. Due to seismic supports on the piping and thermal movement of the piping, an alternate

configuration for the penetration seal is provided. A combination of 34-in. diameter Pyrocreted steel sleeves with double flexible boot seals is provided around each line on the turbine building side of the barrier.

Safety Evaluation Summary

The combustibles in each area translate into an equivalent fire duration of much less than 45 minutes, giving a low fire severity. These combustibles are at least 35 feet away from the penetration on the turbine building side and at least 20 feet away from the penetration on the containment penetration room side. Both areas contain automatic, water suppression systems; a partial area smoke detection system above cable trays is provided in the containment penetration area. Systems required for safe shutdown either have adequate redundancy available or credit is being taken for manual operator actions. As a fire would be confined to one fire area, redundant safe shutdown equipment would remain available.

16. Inaccessible Jumbo Duct Penetrants
FHARE 130, Rev. 0 (Unit 1) (LBIE Log No. 98-084)

Three 4-in. by 4-in., steel tubes ("jumbo ducts"), welded side-by-side, penetrate the 36-in. thick concrete, 3-hour rated fire barrier between the cable spreading room (CSR) and the containment penetration room. Due to their partial physical inaccessibility on one side of the barrier, a penetration seal configuration cannot be assigned. Glass-like epoxy resin is used to seal the cables inside the ducts.

Safety Evaluation Summary

These seal assemblies are similar to adjacent assemblies that have been tested to verify their ability to withstand a 3-hour fire. In fact, in some respects, the subject assemblies are more conservatively configured than the tested assemblies. The maximum fire severity is on the CSR side of the barrier and has an equivalent fire duration of 44 minutes. Most of the combustible material in this area is electrical wiring insulation in cable trays; however, fire stops along the tray runs would be expected to limit the fire to a localized area. Fire detection and suppression equipment exists in both fire areas. Redundant safe shutdown equipment will remain adequately protected as previously credited in the licensing basis.

17. Unrated HVAC Duct Penetrations
FHARE 136, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-109)

Fire hazards Appendix R evaluation (FHARE) 136 evaluates the acceptability of having unsealed duct penetrations in rated fire barriers located in Fire Areas/Zones 13D, 12A, 13E, 12B, 24D, and 23A. FSAR Update Appendix 9.5A has been revised accordingly to address the unsealed penetrations.

Safety Evaluation Summary

The unsealed duct penetrations in the specific fire areas/zones have been evaluated and determined to not adversely impact the DCPP fire protection program. The combustible loading is low in the affected areas and the existing fire protection features are adequate. Therefore, it is concluded that no unreviewed safety question is involved.

18. Concrete Equipment Hatches
FHARE 14, Rev. 3 (Units 1 & 2) (LBIE Log No. 98-072)

Concrete hatches are installed in the plant to aid in equipment access. Some of these are located in 3-hour rated Appendix R fire barriers. The evaluation was originally written to evaluate the existence of up to 2-3/8-in. wide, unsealed gaps around the hatch perimeters. This revision added 4 hatches to those evaluated under this fire hazards Appendix R evaluation (FHARE). These hatches are at the top of each of the residual heat removal (RHR) pump/heat exchanger vaults. Additionally, for the hatches previously covered by the FHARE, revised equivalent fire severities and safe shutdown equipment discussions are provided.

Safety Evaluation Summary

The revisions to discussions related to the original hatches and those being added to this FHARE's scope do not change the reasoning or conclusions of the previous 50.59 evaluation: (1) the revised combustibles loading still results in low equivalent fire severities; and (2) the RHR pump and heat exchanger rooms have partial smoke detection and water spray suppression. Therefore, due to the automatic and manual fire protection features, lack of continuity of combustibles, tortuous path of travel for a fire on an upper level to propagate downward to affect redundant safe shutdown. The only redundancy is the H Bus circuits located on the 76 foot elevation in fire zone 10 (20) and the G Bus circuits on the 107 foot elevation in fire zone 12-B (23-B). The spatial separation between these two elevations represents a tortuous path for products of combustion or fire propagation. Therefore, the capability to achieve safe shutdown is not affected.

19. CCW-1-TCV-130 Replacement (HOT TAP)--DCP M-049319
TES 2-001-N (Units 1 & 2) (LBIE Log No. 97-087)

This design changed replaced the existing TCV-130 with one having better control characteristic for the given system parameters. Changes in the cooling water flow to the let down heat exchanger caused letdown temperature fluctuations resulting in boron concentration/reactivity. The existing TCV-130 was too large to maintain fine control, operating in the lower 2 percent of its

control range. To allow the replacement of the valve without draining header "C" it was necessary to use a HOT TAP to install a by-pass line and smaller TCV-130. A HOT TAP allows the installation of branch connections to existing pipe while the system is "LIVE" which was required because component cooling water (CCW) for the spent fuel pool can not be isolated, even during outages.

Safety Evaluation Summary

The CCW is a safety related system which during refueling outages is relied upon to cool the spent fuel pool. Per FSAR UpdateTable 9.2-7 there are 5 CCW system malfunctions and consequences. Of these, two where potentially effected by the use of a HOT TAP to install the by-pass line. CCW system leakage was eliminated because the HOT TAP machine and associated fittings, flanges and valves where rated for the design pressure and temperature of the system. As a precaution the HOT TAP machine was hydrostaticlly tested prior to breaching the CCW system. The second possible effect was CCW heat exchanger tube rupture which could allow RCS inleakage into the CCW. Due to the relatively small size of debris anticipated in the HOT TAPPING process and the configuration of the system it was determined to be highly unlikely that a tube rupture could occur. Even if a tube where to rupture this would not effect the primary safety function of the CCW to cool safety related loads during Modes 1-4. As a precaution the work was to be completed during Mode 0 (Reactor Defuelled). Completing the work during Mode 0, should a tube rupture, there would not have been inleakage of RCS into the CCW because RCS is depressurized during refueling. Based on the above conclusions the possibility of an accident of a different type than any previously evaluated in the FSAR Update was not created.

20. Non-Rated Features in the Units 1 and 2 Centrifugal Charging Pump Rooms
FHARE 25, Rev. 3 (Units 1 & 2) (LBIE Log No. 98-080)

An additional, triangular-shaped, nonrated penetration of approximately 6-in. by 12-in. is included in this Fire Hazards Appendix R Evaluation (FHARE). It is immediately adjacent to one of the undampered duct penetrations evaluated in an earlier revision of this same FHARE. One side of the penetration is completely covered by a section of structural steel angle. In addition, the combustible loading description for all the related fire areas was updated and a safe shutdown capability analysis was provided.

Safety Evaluation Summary

Using the same reasoning as that provided for the originally-evaluated adjacent duct penetrations, the additional penetration does not create an unreviewed safety question: there is low equivalent fire duration in the related fire zones, automatic fire detection and wet pipe sprinklers are present, a minimum spatial separation between redundant safe shutdown components of 30 feet exists, and

there is an absence of significant quantities of combustibles near the penetrations in Fire Zone 3-C.

21. Undampered Duct Penetrations in Fire Areas/Zones 4-B, 19-E, and TB-7/19-A
FHARE 58, Rev. 3 (Unit 2) (LBIE Log No. 98-117)

Fire hazards Appendix R evaluation (FHARE) 58 was revised to acknowledge the absence of a penetration seal around the ductwork that was previously evaluated for not having fire dampers at the Appendix R fire barriers. Combustible loading and the resulting equivalent fire durations were also revised for the related areas, all of them still remaining in the low fire severity category. A more detailed description of fire protection features in these areas was also provided as well as a safe shutdown capability analysis.

Safety Evaluation Summary

The same fundamental arguments for the original conclusion of no unreviewed safety question still apply: combustibles loadings having low fire severities, automatic smoke detection and sprinkler systems, manual fire fighting capabilities, and the ability to achieve safe shutdown even in the unlikely event a fire was to breach the subject boundary.

22. Lead Shielding Request Per Procedure RP1.ID2
TSR 97-011, Rev. 0 (Unit 1) (LBIE Log No. 97-059)

To allow the plant to install and remove temporary lead shielding in Unit 1 containment for Lines 508, 509, 927, and temporary steel attached to containment annulus structure, located above the residual heat removal (RHR) sump in containment. Shielding will be installed in Modes 5 and 6 only. Shielding will be removed prior to entering Mode 4. Shielding will be installed on operable piping which creates a condition that might affect safe operation of the plant not evaluated in the FSAR Update.

Safety Evaluation Summary

Seismic calculations demonstrate that the components are not adversely affected. The tie-down arrangement of the lead blankets will be such that it will not create a new source, per seismically induced systems interaction, or affect any other safety-related systems, structures or components. The only potential concern would be for the subject residual heat removal lines to suffer a medium energy line break, near the shielding location. In this case during Mode 5 operation, the residual heat removal sump is not required to mitigate the line rupture. The impact of the shielding on the sump could render the sump inoperable, but it would not affect the safe shutdown of the plant. The DCPP accident analysis does not postulate a Mode 5 loss-of-coolant accident or line

break. Based on the above criteria and justification, an unreviewed safety question is not involved.

23. Mode 4 to Mode 3, Obtain New RVLIS DP3 coefficients
AR A0425503 (Unit 1) (LBIE Log No. 97-095)

This LBIE was a part of Attachment 9.10 of Operations Procedure OP L-0 that obtained Plant Staff Review Committee approval for Unit 1 to transition from Mode 4 to Mode 3 with Train A of reactor vessel level indication system (RVLIS) out-of service. RVLIS is required per Technical Specification (TS) 3.3.3.6 for Modes 1-3.

Train A of RVLIS was required to be out-of service to perform the data collection required to obtain new DP3 coefficients while the plant heats up from refueling to Mode 3, normal operating pressure/normal operating temperature conditions.

The action to reperform the DP3 curve was corrective action from NCR N0002016.

Safety Evaluation Summary

The LBIE screen for this condition screened “Yes” as a change to the system operation as described in the FSAR Update. The safety evaluation determined that an unreviewed safety question is not involved based on the Technical Specifications allowing the plant to transition modes while under Action (A) for TS 3.3.3.6 for RVLIS (ie TS 3.0.4 exempt). With Train B fully in service during this evolution and the system exempt from the provisions of TS 3.0.4, the facility design or license was not impacted.

24. Steam Generator Tube Support Plate Thin or Missing Ligaments
AR A0432415, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-099)

Thin or missing steam generator (SG) tube suport plate (TSP) ligaments were identified by review of DCPP Units 1 and 2 SG eddy current data and confirmed by visual inspections of DCPP Unit 1 SG TSPs conducted in 1R8.

Safety Evaluation Summary

Operation of the DCPP Units 1 and 2 SGs with thin or missing TSP ligaments will not adversely affect SG tube structural and leakage integrity during normal operation and accident conditions. An active tube wear mechanism is not occurring at locations of thin or missing TSP ligaments, and no additional tubes are expected to experience deformation during a postulated loss-of-coolant accident plus seismic event.

25. Continued Operation With Cable Dampers for Steam Generator U-Bends
FTI Document 51-1264525, Rev. 1 (Units 1 & 2) (LBIE Log No. 98-023)

The subject of this licensing basis impact evaluation (LBIE) was the qualification of steam generator (SG) U-bend dampers designed by Westinghouse and installed in eight potentially susceptible tubes (November 1988 in the Unit 2 second refueling outage and October 1989 in the Unit 1 third refueling outage) to increase margins against flow-induced vibration in response to NRC Bulletin 88-02. This LBIE extended the qualification of the damper to full lifetime without the need for inspection based on further damper testing and the supporting 50.59 evaluation performed by Framatome Technologies.

Safety Evaluation Summary

Tubes that were susceptible to flow-induced fatigue cracking (WCAP 12064) have been plugged and dampened by installation of Westinghouse cable dampers to meet the requirements of NRC Bulletin 88-02. Therefore, in the dampened tubes, the tube plugs act as the reactor coolant system (RCS) pressure boundary, and the damper will not affect the function of the plugs. The increased wear in the damper/tube system has been evaluated through testing and analysis and has been determined to not affect the dynamic characteristics of the system or result in failure of the system. The relevant accident that has been previously evaluated in the FSAR Update is a SG tube rupture (SGTR). The probability of occurrence of an SGTR event is not increased because the dampers are qualified for continued performance of their safety function. Based upon the above criteria and justification, an unreviewed safety question is not involved. Also, a change to the Technical Specifications is not involved.

26. Determination of the Uncovered Screen Area and Pressure Drop Across the Screens in the Recirculation Sump After Paint and Insulation Severs From Objects Inside Containment During Post-LOCA Environment
Calculation M-591, Rev. 11 (Units 1 & 2) (LBIE Log No. 97-100)

Calculation M-591 was inconsistent with insulation assumptions described in the FSAR Update. It was shown that the sump analysis did not conflict or invalidate FSAR Update statements regarding the acceptability of paint chips plus transport of 100 percent of damaged insulation during a large break loss-of-coolant accident (LOCA). Instead, this calculation revision identified that a more limiting scenario exists, shredded insulation during a small break LOCA, and evaluated that scenario with new assumptions about insulation transport. Two key changes to the evaluation methodology were made: containment flood levels were determined for small break LOCAs, and less than 100 percent of fiberglass insulation in the form of shredded debris was assumed to reach the sump and deposit evenly over the screen. The impact of paint chip and fiberglass insulation debris were thus evaluated together for the first time.

Safety Evaluation Summary

LOCAs are the only accidents evaluated in the FSAR Update that rely upon sump operability. The function of the sump is to screen out debris while providing sufficiently low flow resistance such that the residual heat removal (RHR) pumps will not draw down the sump level and cavitate. The FSAR Update statement that transport of 100 percent of loosened fiberglass insulation concurrent with transport of degraded paint particles would not prevent the sump from being operable only applied to large break LOCAs with the assumption that the insulation remained intact. Calculation M-591 now credits less than 100 percent of insulation transport due to obstacles, the high specific gravity of fiberglass, and the low flow velocities through the containment during recirculation. A more limiting scenario was identified for screen operability, a small break LOCA with shredded fiberglass insulation spread out over the entire screen, and M-591 Revision 11 demonstrated that the sump remains operable under this new scenario.

27. Fiberglass Insulation Debris From HELB Inside Containment
Calculation N-042, Rev. 1 and N-051, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-093)

Calculations N-042 and N-051 were revised to incorporate the latest design basis methodology for determining the quantity of fiberglass insulation debris generated due to various high energy line breaks (HELBs) inside containment. The leak-before-break (LBB) methodology was incorporated into the calculations to eliminate the dynamic effects of reactor coolant loop HELBs on fiberglass insulation, and certain non-terminal end breaks were eliminated from consideration based on the latest jet impingement study and pipe whip study. Although use of the LBB methodology was approved by the NRC for DCPP in March 1993, Revision 11A of the FSAR Update did not reflect this revised licensing basis, so this safety evaluation was required to take credit for LBB in the insulation calculations.

Safety Evaluation Summary

General Design Criterion 4 states that structures, systems and components shall be appropriately protected against the dynamic effects, including missiles, pipe whip, and discharging fluids that may result from equipment failures outside the nuclear power unit. However, the dynamic effects associated with postulated pipe ruptures in the nuclear power unit may be excluded from design basis when the analysis reviewed and approved by the NRC demonstrates that the probability of a fluid system rupture is extremely low under conditions consistent with the design basis for the piping. The NRC determined that class 1 piping breaks at DCPP are sufficiently low that the dynamic effects associated with postulated primary pipe breaks need not be a design basis. The NRC approved DCPP's LBB evaluation in March 1993. Thus, elimination of the dynamic effects

of postulated RCS loop piping ruptures from fiberglass insulation debris evaluations is within the licensing basis of the plant.

28. LHUT Dose Reanalysis/Calculation N-160
Calculation N-160, (Units 1 & 2) (LBIE Log No. 97-092)

FSAR Update Section 15.5, Liquid Holdup Tank (LHUT) Rupture, was reanalyzed to conform with Regulatory Guide (RG) 1.29, "Seismic Design Class." RG 1.29 specifies that some systems must meet seismic qualification criteria or the design basis accident offsite dose consequences must be less than 0.5 rem whole body. The LHUTs and associated piping were purchased seismic qualified but not maintained seismic qualified. The dose consequences from the original LHUT rupture was 1.44 rem. The reanalysis results are 0.152 rem. Therefore RG 1.29 is met.

Safety Evaluation Summary

The reanalysis of the postulated offsite dose from a LHUT rupture does not involve any changes to plant systems, structures or components. The reanalysis is based on conservative assumptions with respect to the original analysis contained in the FSAR Update. The reanalysis results show a reduction in offsite dose rates from the postulated LHUT rupture. Thus, the consequences of the LHUT rupture previously evaluated in the FSAR Update are reduced, not increased.

29. Control Room Vent
AR PK15-06, Rev. 8 (Unit 2) (LBIE Log No. 97-144)

This procedure revision revised the response to losing subtrains of control room ventilation system (CRVS) cooling, as described in the FSAR Update. Previously, there was no guidance provided for this event, since there are four equally redundant subtrains available to perform CRVS functions. However, to prevent the possibility of overlooking the FSAR Update-described response, these actions were added to the procedure.

Safety Evaluation Summary

Since the proposed procedure revision adds the detail as described in the FSAR Update, there is no change to the facility or operation as described in the FSAR Update. The evaluation was performed since the FSAR Update describes response to loss of all CRVS in moderate detail. An unreviewed safety question is not involved.

30. Revision of the Bases for Technical Specification 3/4.9.2, "Refueling Operations - Instrumentation"
Technical Specification Bases 3/4.9.2 (Units 1 & 2) (LBIE Log No. 97-219)

The revision of the Bases for Technical Specification (TS) 3/4.9.2, "Refueling Operations - Instrumentation" allows use of an alternate source range (SR) monitor during Mode 6 (refueling) in the event one of the two normal SR channels becomes inoperable. (Note: This has already been reported to the NRC in Letter DCL-97-035, dated March 18, 1997)

Safety Evaluation Summary

The use of alternate SR indication provided by post-accident neutron flux monitors is equivalent to use of a portable detector allowed by TS Bases per License Amendments 46 and 45. This condition does not involve an unreviewed safety question. PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by this TS Bases revision.

31. Revision of Technical Specification Bases 3/4.7.3 and 3/4.7.12 - Change Component Cooling Water System Design Basis Temperature
Technical Specification Bases 3/4.7.3 and 3/4.7.12 (Units 1 & 2) (LBIE Log No. 97-221)

The change to Technical Specification (TS) Bases 3/4.7.3, "Vital Component Cooling Water," and 3/4.7.12, "Ultimate Heat Sink," increased the maximum temperature at which the component cooling water (CCW) system may operate after a design basis event from 132°F for 120 minutes to 140°F for six hours after the event, returning to a maximum of 120°F thereafter. This revision reflects upgraded qualifications of CCW components and equipment cooled by CCW to show that they can function with the higher temperature cooling water. An administrative change to relocate the temperature limit from Bases 3/4.7.12 to Bases 3/4.7.3 was also made to improve consistency.

Safety Evaluation Summary

PG&E has performed a detailed, component level review of the CCW equipment, support system equipment, and the equipment cooled by CCW. Each device was reviewed using vendor information as needed, and found to function properly with the increased cooling water temperature. The change did not require modification to any equipment or system, other than a minor adjustment to CCW heat exchanger auxiliary saltwater (ASW) discharge throttle valves to mitigate possible cavitation and resetting a post-accident sampling system (PASS) temperature switch setpoint to accommodate the new temperature limit. These valves are normally throttled already, and the required minimum valve position imposed by this change is within the range of the current normal operation of these valves. The imposition of these valve position requirements

serves to minimize potential cavitation effects and has no detrimental impact on the capability of the ASW to perform its normal and emergency functions. Based on detailed evaluations of all affected systems, components, and structures, it has been demonstrated that they will perform their intended safety functions with the increased CCW water temperature conditions.

32. Evaluation of Zinc Addition in Cycle-9 at Diablo Canyon Unit 1
Westinghouse Letter SECL-97-207 (Unit 1) (LBIE Log No. 98-038)

The addition of zinc to the reactor coolant system (RCS) will be done for the purpose of decreasing the incidence of primary water stress corrosion cracking in the steam generator U-tubes. Zinc acetate will be injected via the chemical and volume control system (CVCS) system to achieve an RCS zinc concentration of 35-40 ppb during a nine month trial period. A secondary benefit will be the reduction of radiation fields in the RCS. Tests will be performed to determine its effectiveness.

Safety Evaluation Summary

The injection of zinc into the RCS has not previously been done at DCPP nor is it described in the FSAR Update. Analysis of zinc injection performed at Farley 2 demonstrated that zinc did not have a deleterious effect on the function or operation of any RCS components with the potential exception being fuel. A root cause evaluation concluded that zinc may have a small detrimental effect on fuel cladding oxidation. For this reason, a conservative penalty was included in the fuel analysis for the Unit 1 Cycle 9 core. Results of the analysis demonstrate that all fuel design criteria are still met.

Consideration for the impact of zinc on post-accident hydrogen, LOCA heat transfer, containment sump pH, source term, and RCS dilution was all found to be insignificant. Consequences of an accident will therefore not be increased by the addition of zinc.

September 28, 1998

PG&E Letter DCL-98-136

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

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
10 CFR 50.59 Report of Facility Changes, Tests, and Experiments
for the Report Period May 24, 1996 - March 28, 1998

Dear Commissioners and Staff:

Pursuant to 10 CFR 50.59, "Changes, Tests, and Experiments," enclosed is the safety evaluation report for Diablo Canyon Power Plant Units 1 and 2. The report primarily includes safety evaluations, termed licensing basis impact evaluations (LBIEs) by PG&E, prepared during the interval May 24, 1996, to March 28, 1998, which corresponds to the reporting interval for the Diablo Canyon Final Safety Analysis Report Update, Revision 12. In addition, a few LBIEs prepared as late as September 1, 1998, are included.

The enclosed report provides a brief discussion of the changes and a summary of the LBIEs for the following change categories:

- Facility Changes
- Temporary Modifications, Electrical Jumpers and Lifted Leads, Mechanical Jumpers and Bypasses, and Test Equipment
- Procedure Changes
- Tests and Experiments
- Equipment Control Guidelines
- FSAR Update Changes
- Other Changes

The Plant Staff Review Committee has reviewed the LBIEs and determined that the changes do not involve unreviewed safety questions or require changes to the Diablo Canyon Power Plant Technical Specifications.

Sincerely,

Gregory M. Rueger

cc: Steven D. Bloom
Ellis W. Merschoff
Gregory A. Pick (w/o enc.)
David L. Proulx
Diablo Distribution (w/o enc.)

Enclosure

RLR/1392

Enclosure
PG&E Letter DCL-98-136

10 CFR 50.59 REPORT OF FACILITY CHANGES, PROCEDURE CHANGES, TESTS, AND EXPERIMENTS

MAY 24, 1996 - MARCH 28, 1998

Pacific Gas and Electric Company
Diablo Canyon Power Plant, Units 1 and 2
Docket Nos. 50-275 and 50-323

A. FACILITY CHANGES

A. FACILITY CHANGES

A. FACILITY CHANGES

B. TEMPORARY MODIFICATIONS, ELECTRICAL JUMPERS AND LIFTED LEADS, MECHANICAL JUMPERS AND BYPASSES, AND TEST EQUIPMENT

C. PROCEDURE CHANGES

C. PROCEDURE CHANGES

D. TESTS AND EXPERIMENTS

E. EQUIPMENT CONTROL GUIDELINES

F. FSAR UPDATE CHANGES

F. FSAR UPDATE CHANGES

F. FSAR UPDATE CHANGES

G. OTHER CHANGES

G. OTHER CHANGES

A. Facility Changes

1. Restore the Fire Barrier Between Fire Area 4-B and 4-B-2
DCP A-050330, Rev. 0 (Unit 2) (LBIE Log No. 97-045)

The 2-hour fire barrier separating Fire Area 4-B and 4-B-2 is degraded because Pullbox BPG5 is partially embedded on the southside of the 2-hour plaster fire wall. Conduit k6944 is a safe shutdown circuit with a 1-hour 3M fire wrap on the north side of the fire barrier running along the north face of the plaster wall and connecting to Pullbox BPG5. To satisfy the requirement for a 2-hour plaster wall, provide a 2-hour pyrocrete enclosure behind the protuded Pullbox BPG5.

Safety Evaluation Summary

The degraded 2-hour fire rated plaster wall configuration was modified to meet the requirements of 10 CFR 50, Appendix R. This modification is required to maintain separate redundant trains of safe shutdown components, per Section IIIg of Appendix R.

2. Cathodic Protection for ASW Supply Pipelines
DCP C-049169, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-217)

This design change is for installation of a cathodic protection system for the existing Class I auxiliary saltwater (ASW) pipelines and new bypass ASW pipelines near the intake to reduce corrosion of the pipelines.

Safety Evaluation Summary

The cathodic protection system is largely buried, with most components not near the ASW pipes. The modification does not change any system interfaces and has no impact on ASW system capacity to perform its design function. The ASW system is not the cause of any FSAR Update analyzed accidents. Therefore, it is concluded that installation and operation of the cathodic protection system does not involve an unreviewed safety question.

3. Auxiliary Saltwater Bypass
DCP C-049207, Rev. 6 (Units 1 & 2) (LBIE Log No. 96-018)
DCP C-050327, Rev. 0 (Unit 2) (LBIE Log No. 97-179)
DCP C-050327, Rev. 1 (Unit 2) (LBIE Log No. 98-013)
DCP C-050327, Rev. 0 (Unit 2) (LBIE Log No. 97-157)
ASW Piping Bypass Project Letter, Rev. 0 (LBIE Log No. 97-007)

This design change installed a bypass around approximately 800 feet of Unit 1 and 200 feet of Unit 2 auxiliary saltwater (ASW) system piping. The project was initiated due to a concern that localized corrosion was occurring in the portion of the piping buried below sea level in the tidal zone outside the intake structure. In

addition, upgraded flow and temperature instrumentation was installed. The project was installed in phases. The project safety evaluation determined the change did not involve a unreviewed safety question. After interaction with the NRC, PG&E submitted a License Amendment Request (LAR 97-11) to resolve concerns with the analyzed potential for liquefaction in a small area below a portion of the Unit 1 piping. The LAR was later revised to apply only to Unit 1. The NRC has not completed their review of the LAR.

Safety Evaluation Summary

The installation of the bypass piping does not impact the ASW system design basis parameters. The rerouting and increased length of the bypass causes a small reduction of ASW flow, however the design and licensing basis functions of the ASW system are not impacted. The routing of a portion of the Unit 1 piping over an area that may be impacted by seismic induced liquefaction is conservatively included in the design. The LAR was submitted to allow the NRC to review the unreviewed safety question introduced into the Diablo Canyon FSAR Update by the liquefaction issue.

4. Intake Cove Revetment
DCP C-049310, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-015)

This DCP reinforced the rip rap revetment along the north shore of the intake cove, through the pumping of concrete into voids between the existing armor stones. This reinforcement is required in order to protect the soil surrounding and supporting buried auxiliary saltwater (ASW) bypass piping (installed per DCP C-49207) from damage associated with the tsunami-storm wave loading conditions defined in DCM T-9.

Safety Evaluation Summary

No 50.59 safety evaluation was performed for this design change, as the requirements of the safety evaluation screen were met. The safety evaluation was performed for an environmental evaluation as the performance of this work created discharges to the ocean that could impact PG&E's National Pollutant Discharge Elimination System permit. It was determined that the change did not involve an unreviewed environmental question.

5. Provide Pyrocrete Fire Barriers
DCP C-049339, Rev. 0 (Unit 1) (LBIE Log No. 97-160)

This modification involved the design of fire barrier materials, which protect redundant safe shutdown circuits from the effects of a fire. The Pyrocrete maintenance doors at Elevation 85 feet in the 12-kV switchgear room and the Transite barriers at Elevation 76 feet in the 12-kV cable spreading room will be

modified with an additional layer of Pyrocrete material to provide the required 2-hour fire rating.

Safety Evaluation Summary

The Pyrocrete maintenance doors at Elevation 85 feet in the 12-kV switchgear room and the Transite barriers at Elevation 76 feet in the 12-kV cable spreading room will be modified with an additional layer of Pyrocrete material to provide the required 2-hour fire rating to protect one train of redudant circuits for equipment per 10 CFR 50, Appendix R, Section III. G.2.

6. Unit 2 - Yard Pullbox: Install Fire Barrier
DCP C-050405, Rev. 0 (Unit 2) (LBIE Log No. 97-180)

During review of issues associated with yard pull boxes containing safe shutdown circuits, it was discovered that Transite panel separation barriers in Pull Boxes BPO 33, 33A, 33B, 33C, 43, 43A, 43B, and 43C were not qualified fire barriers. The Transite panels were not approved fire barriers. 10 CFR 50, Appendix R, Section III.G.2, requires a 3-hour rated fire barrier to be installed for one train of redundant circuits for equipment that is required to achieve and maintain safe shutdown and is located within the same fire area. As corrective action for Nonconformance Report N0001887, it was necessary to remove the unqualified Transite panels from the pull boxes and replace them with pre-cast 3-hour rated pyrocrete barriers to completely seal and separate the safe shutdown circuits in separate compartments within the pull boxes.

Safety Evaluation Summary

The 10 CFR 50.59 safety evaluation was performed because unqualified Appendix R fire barriers were replaced with qualified tested barriers. Although FSAR Update fire barrier descriptions are not particularly specific, the DCP was considered to be a modification to the fire protection system (FSAR Update Section 9.5). The design change brings fire protection in the Unit 2 yard pull boxes into conformance with NRC regulations and licensing commitments. The Unit 2 yard pull boxes fire barriers are not associated with initiation of any evaluated FSAR Update accident. The design basis accident is a pull box fire that is mitigated, not caused by, the subject barriers. The qualified pull box fire barriers ensure that at least one of the redundant safe shutdown circuits located in the yard pull boxes will be available for safe shutdown following a postulated fire. Combustible loading was not increased. New combustible materials were not added. The qualified pull box fire barriers ensure that a single fire will not affect both safe shutdown trains in the subject yard pull boxes. Installation of the barriers did not raise the possibility of a new equipment malfunction because the new barriers were fabricated outside the pull boxes and set in place using approved procedures.

7. Install Fire Barriers in Fire Area 20
DCP C-050339, Rev. 0 (Unit 2) (LBIE Log No. 97-014)

This design change modified the design of fire barrier materials that protect redundant shutdown circuits from the effects of a fire. An additional layer of Pyrocrete was added to the Pyrocrete maintenance doors in the 12-kV switchgear room and to the Transite fire barriers in the 12-kV cable spreading room to provide the required 2-hour fire rating. The modification was a required corrective action for Nonconformance Report N0001887.

Safety Evaluation Summary

This 10 CFR 50.59 evaluation was performed because FSAR Update Appendix 9.5A takes credit for the Pyrocrete barriers and Transite panels as providing the fire protection required for Fire Area 20. Prior to this modification, the subject barriers were not qualified. The new fire barriers are qualified by testing. The FSAR Update description was modified to reflect the change. Adding qualified fire barriers to protect redundant safe shutdown circuits does not affect probability, possibility, or consequences of any analyzed or unanalyzed accident or equipment malfunction. No equipment was modified; safety margins were not affected. The change was made to bring the fire protection in Fire Area 20 into conformance with NRC regulations. A two-hour fire barrier is required to meet DCPP's commitment for fire protection in the subject area. The combustible loading in the area is less than one hour.

8. Battery 13 Replacement
DCP E-049297, Rev. 0 (Unit 1) (LBIE Log No. 96-027)

This design change was to replace Battery 13 with a larger capacity battery. The major scope of work involved replacing 60 cells, fabricating a new step rack, modifying existing battery rack end restraints, and replacing feeder cable and inter-rack cables with 6 - #4/0 AWG cable. This design changed increased the battery capacity from 1800 amp-hr to 2320 amp-hr, which restored the both the vital 125-Vdc system and vital 120-V instrument ac system with positive load growth margins.

Safety Evaluation Summary

This design change did not affect the design basis of the 125-Vdc system. The larger capacity did not change/affect the electrical characteristic supplied to any of the 125-Vdc loads or cause any load to be operated outside their design or testing limits. The new Class 1E battery met the original design specifications for material and qualification (new qualification test was required). The new battery did not impose any new electrical load, and the existing battery charger, dc bus, or dc distribution panel/breakers did not require modification. No new operational or failure modes were introduced nor were there any changes

required to the Technical Specification Bases. The larger battery did increase the battery room floor loading and was accounted for and accepted by Civil engineering calculations. It also increased the amount of hazardous material since the larger battery uses about 60 gallons more sulfuric acid (electrolyte); this was evaluated for in the LBIE Environmental Protection Evaluation and is to be accounted for in the DCPP Hazardous Materials Business Plan.

9. Change the Tap Settings for the Vital MCC Transformers
DCP E-049321, Rev. 0 (Unit 1) (LBIE Log No. 96-037)
DCP E-050321, Rev. 0 (Unit 2) (LBIE Log No. 97-125)

Calculation 357-DC evaluated and provided the optimized transformer tap voltage settings for both minimum and maximum system voltage conditions under various modes of operation. Based on the calculation the vital distribution transformers (motor control center) taps were changed. The calculation and changes were a result of adding load tap changing (LTC) 230/12-kV transformers.

Safety Evaluation Summary

The choice of the tap setting is to provide adequate voltage at the terminals of Class 1E equipment under design basis accident conditions. The tap settings are not covered by Technical Specifications, and the safety functions are assured since these tap changes keep the 4-kV and 480-V buses within the design required voltage levels. Technical Specification 3.8.1 states. "… ensures that sufficient power will be available to supply the safety related equipment." The technical specification requirements and their bases' margins of safety are maintained by optimizing the tap settings for these transformers.

10. Replace SUT 11 With New Transformer Equiped With LTC
DCP E-049322, Rev. 0 (Unit 1) (LBIE Log No. 96-042)

This design change replaced the Unit 1, 230/12-kV startup transformer (SUT) 11 with a new transformer that uses an automatic load tap changing (LTC) device to control the voltage. This change resolved the short circuit withstand capability problem of SUT 11 that was discovered following the study that was completed as a result of the Unit 1 auxiliary transformer failure in October 1995. It also helped resolve the voltage problem that existed at the 4-kV and 480-V buses when supplied from the 230-kV startup source, which was not adequate under certain design basis operating scenarios to support the operation of safety-related equipment. This design change also replaced the existing 230-kV Disconnect Switch 211-1 with a circuit switcher that provides load break capability to allow removal of SUT 11 from service without deenergizing the 230-kV source.

Safety Evaluation Summary

The replacement of SUT 11 with a new transformer equipped with LTC for voltage control does not alter the original configuration of the electrical distribution system. It enhances the capability of the 12-kV and the 4-kV electrical distribution systems to have sufficient voltage for a successful transfer of the plant auxiliary loads to the startup source following a unit trip. This change also eliminates the potential for "double sequencing" of the 4-kV vital loads during an accident by providing adequate voltage to the 4-kV vital buses from the 230-kV source. The new transformer's design exceeds the short circuit capability requirement. So its malfunction is less likely than the old transformer. Malfunction of the LTC feature is the only new failure that was not a consideration for the old transformer. A failure modes and effects evaluation found that the possibility of a malfunction of the LTC is very unlikely and is no different than the possible failures already considered for the transformer. Malfunction of the LTC is monitored in the control room through voltage indication and annunciator alarm. Under the worst case scenario, during an accident, failure of the LTC in the boost position to maintain minimum voltage at the 4-kV vital buses would be detected by the second-level undervoltage relay and the 4-kV vital buses will transfer to the emergency diesel generators as per the original design.

11. Replacement of CFCU Timers
DCP E-049344, Rev. 1 (Unit 1) (LBIE Log No. 97-210)

All containment fan cooler unit (CFCU) timers in Units 1 and 2 were replaced with more accurate digital-type, Agastat DSC timers, along with internal wiring changes in the CFCU control circuits. The primary reason for the replacement was excessive drift in the old timers. The starting logic has also been modified such that CFCUs will auto-start with low speed under auto bus transfer conditions, regardless of the high/low speed control switch position.

Safety Evaluation Summary

The replacement DSC timers will provide equivalent (or better) performance than the existing timers. The starting logic modification makes the low speed start consistent with an existing administrative control. Therefore, this change does not involve an unreviewed safety question.

12. Battery 23 Replacement.
DCP E-050297, Rev. 0 (Unit 2) (LBIE Log No. 97-121)

Vital Battery 23 Replacement DCP/DCN implemented in the Unit 2 eighth refueling outage installed larger battery cells to accommodate increased dc loading from the new 120-Vac instrument uninterruptible power supply (UPS) and provide for future growth.

Safety Evaluation Summary

The replacement of Vital Battery 23 with larger cells increased the dc bus loading capability and supported the new larger UPS loads. There were no increases in the probabilities or consequences of any accidents previously evaluated in the FSAR Update as a result of this change. There were no unreviewed safety questions.

13. On-Line Replacement of Unit 2 SUT 21 and Its Disconnect Switch 211-2
DCP E-050322, Rev. 1 (Unit 2) (LBIE Log No. 97-183)
DCP E-050322, Rev. 1 (Unit 2) (LBIE Log No. 97-134)

The on-line replacement entailed removing the existing Startup Transformer (SUT) 21 and Disconnect Switch 211-2 and installing the new transformer and circuit switcher while Unit 2 was operating at power. During on-line replacement, the standby startup power to the Unit 2 12-kV startup bus was established by closing the 12-kV startup buses tie breaker. With the tie breaker closed, SUT 11 provided offsite power to both the Unit 1 and Unit 2 startup buses.

Safety Evaluation Summary

While the plant is in an on-line replacement configuration using one startup transformer, the design and licensing basis for the DCPP offsite power is not compromised since the shutdown power for Unit 2 in the event of an accident will be supplied by the available Unit 1 startup transformer while providing a standby power source to Unit 1. The operating instructions of Table I outlined in O-23 will be still applicable.

To handle an anticipated dual unit trip under the on-line replacement configuration, additional compensatory measures would be required, i.e., reduced 12-kV bus transfer, operating Morro Bay Power Plant (MBPP) Units 3 or 4 with a minimum voltage of 234 kV maintained at the DCPP 230-kV buses and availability of all six diesel generators to guard against a loss of offsite power. DCPP design basis allows reliance on the diesel generators for dual unit trips, since there is no common initiating event that would cause an accident in both units simultaneously.

Having a reduced 12-kV load transfer on both units provides additional offsite power margin to the vital buses in case of an accident at one unit or dual-unit trip. The reduced transfer does not result in an increase in probability or consequences of an accident.

There is an increased safety benefit and reduced risk in doing the replacement on-line since the plant configuration in Modes 1 through 4 is under much stricter and better control than in Modes 5 and 6.

There is no increased risk of plant operation while on-line replacement is being performed and the margin of safety as defined in the basis for any Technical Specification will be enhanced as a result of a better voltage control of the new transformer through its LTC. By maintaining a higher voltage at the 12-kV startup buses, the voltages at the 4-kV and 480-V busses will have better voltages providing additional margin of safety.

14. Replacement of CFCU Timers
DCP E-050344, Rev. 1 (Unit 2) (LBIE Log No. 97-211)

All containment fan cooler unit (CFCU) timers in Units 1 and 2 were replaced with more accurate digital-type, Agastat DSC timers, along with internal wiring changes in the CFCU control circuits. The primary reason for the replacement was excessive drift in the old timers. The starting logic has also been modified such that CFCUs will auto-start with low speed under auto bus transfer conditions, regardless of the high/low speed control switch position.

Safety Evaluation Summary

The replacement DSC timers will provide equivalent (or better) performance than the existing timers. The starting logic modification makes the low speed start consistent with an existing administrative control. Therefore, this change does not involve an unreviewed safety question.

15. Install Automatic Control for the LTC of SUT 21.
DCP E-050365, Rev. 0 (Unit 2) (LBIE Log No. 97-135)

This design change installed the automatic controls of the load tap changer (LTC) to the newly installed Unit 2 Startup Transformer (SUT) 21 which was used as a fixed tap transformer up to this point. The new SUT 21 and Circuit-Switcher 211-2 were installed in November 1997 under DCP E-50322. The installation of the automatic controls of the LTC put the system configuration for Unit 2 SUT 21 in the same configuration as that of Unit 1 Startup Transformer SUT 11.

Safety Evaluation Summary

The replacement of SUT 21 with a new transformer equipped with LTC for voltage control does not alter the original configuration of the electrical distribution system. It enhances the capability of the 12-kV and the 4-kV electrical distribution systems to have sufficient voltage for a successful transfer of the plant auxiliary loads to the startup source following a unit trip. This change also eliminates the potential for “double sequencing” of the 4-kV vital loads during an accident by providing adequate voltage to the 4-kV vital buses from the 230-kV source. The design of the new transformer exceeds the short circuit

capability requirement. So its malfunction is less likely than the old transformer. Malfunction of the LTC feature is the only new failure that was not a consideration for the old transformer. A failure modes and effects evaluation determined that the possibility of a malfunction of the LTC is very unlikely and no different than the possible failures already considered for the transformer. Malfunction of the LTC is monitored in the control room through a voltage indication and annunciator alarm. Under the worst case scenario, during an accident, failure of the LTC in the boost position to maintain minimum voltage at the 4-kV vital buses would be detected by the second level undervoltage relay and the 4-kV vital buses will transfer to the emergency diesel generators as per the original design.

16. Alternate Power Source to Spent Fuel Pool Pumps
DCP E-050381, Rev. 0 (Unit 2) (LBIE Log No. 97-216)

This design change adds alternate Class 1E power sources to spent fuel pool (SFP) Pumps 21 and 22. The alternate Class 1E power source will be available for use during electrical bus outages and maintenance periods and reduce the need for the use of temporary power jumpers to maintain one SFP pump available.

Safety Evaluation Summary

Providing an alternate Class 1E power source to the SFP pumps reduces the need for energized jumpers during outages. Previous jumper installation has caused increased wear and degradation of cables and terminations, as well as personnel hazards while installing the jumpers. Adding the alternate power source does not affect accidents or safety margin and therefore does not involve an unreviewed safety question.

17. Removal of Flow Controllers from Unit 1 AB and FHB HVAC System Supply and Exhaust Inlet and Downgrading Associated Flow Instruments from "Class I" to "Class IC"
DCP H-049326, Rev. 0 (Unit 1) (LBIE Log No. 97-205)
DCP H-050326, Rev. 0 (Unit 2) (LBIE Log No. 97-185)

This design change deleted automatic control of inlet air flow to the auxiliary and fuel handling building ventilation system fans. Controllers modulating inlet vanes of Fans E1, E2, S31, S32, E4, E5, E6, S1, and S2 to maintain predetermined flow from these fans are removed and they are replaced by manual pressure regulators that main inlet vanes at a predetermined (almost open) position. Also the change downgrades associated flow elements (sensors) from Class I to Class IC.

Safety Evaluation Summary

The design change simplifies operation and improves availability and reliability of the Unit 1 auxiliary building and fuel handling building HVAC systems. This change impacts the description in Section 9.4.2.2 of the FSAR Update. The change does not alter design intent and functionality and was determined to not involve an unreviewed safety question. Recommendation to remove the controllers is based on experience with the HVAC system operation.

18. Upgrade Debris Screens to Design Class 1
DCP H-050401, Rev. 0 (Unit 2) (LBIE Log No. 98-007)

The DCPP Operating License allows opening of the 48-in. containment purge valves during power operation. PG&E had committed in Supplement 9 of the Safety Evaluation Report to install debris screens on the containment side of the valves to ensure that debris will not lodge in the valve seat to prevent full closure of the valves in the event of an accident. This debris prevention function is safety related. However, currently, the Q-List, Design Criteria Memorandum (DCM) T-16, and DCM S-23A classify the debris screens as Design Class II, Seismic Category I. Design Change Package H-50401 upgrades the debris screens from Design Class II to Design Class I. This upgrade is required to ensure that the debris screens will perform their safety-related function.

Safety Evaluation Summary

The containment purge valves may be open during plant Modes 1-4 for purging of the containment. In the event of an accident, the valves must be able to fully close to maintain the integrity of the containment. The consequences of an accident evaluated in the FSAR Update is based on full closure of the isolation valves within the predetermined stroke time. This ensures that the off-site 10 CFR 100 dose guideline value is not exceeded. The safety-related function of the debris screens is to prevent debris generated during an accident from

lodging in the valve seat such that it may affect closure of the valves. Upgrading the design classification of the debris screens and associated components to Design Class I will ensure that this safety-related function can be fully met and that the consequences of an accident would not be increased.

19. Met Tower Instrument Upgrade
DCP J-049101, Rev. 1 (Unit 1) (LBIE Log No. 97-189)

This design change replaced the obsolete meteorological instrumentation on both the primary and backup meteorological towers. The supplementary measurement instrumentation is mounted permanently on top of the backup meteorological shack. This design change was implemented when the equipment was removed from service for its bi-annual calibration.

Safety Evaluation Summary

The design change upgrades the meteorological instrumentation to maintain the requirements of Regulatory Guide (RG) 1.97. The met instrumentation is nonsafety related, is used for monitoring purposes only, and is not part of any accident scenarios previously evaluated in the FSAR Update. The meteorological instrumentation does not interface with any equipment important to safety. All requirements required by RG 1.97 are maintained.

20. Safety Parameter Display System Replacement
DCP J-049123, Rev. 0 (Unit 1) (LBIE Log No. 96-005)

This design change removed and replaced the existing Unit 1 emergency response facility data system (ERFDS). The ERFDS/SPDS is being replaced to solve the following problems: (a) software errors exist which result from operational changes or latent software defects in the original B&W software, (b) parts are not available for hardware failures impacting system availability, and (c) ERFDS software changes can only be purchased at great expense from the original vendor.

Safety Evaluation Summary

The SPDS is functionally and spatially incapable of creating design basis events comparable to those evaluated in the FSAR Update. The replacement of the SPDS and the abandonment of the ERFDS tape function and use of the plant process computer function in the Technical Support Center and emergency operations facility do not introduce any new equipment, configurations, or hazards not previously evaluated.

21. Replacement of Plant Vent Gross Gamma Monitors RM/RE-29
DCP J-049193, Rev. 0 (Unit 1) (LBIE Log No. 96-022)
DCP J-050193, Rev. 0 (Unit 2) (LBIE Log No. 96-023)

This design change replaces the entire analog RM-29 radiation monitoring channel with more modern digital equipment. Components included in this change include the local detector/preamp assembly (RE-29) and control room readout module (RM-29). The local indicator (RI-29A) is no longer required and will be permanently removed. This design change also installs a rigging support structure local to the detector assembly to add in disassembly of heavy lead shields during calibration activities.

Safety Evaluation Summary

This design replaces the existing obsolete RM-29 radiation monitor with a more reliable digital radiation monitor having the same range, functionality and peripheral interfaces. Removal of RI-29A (referenced in FSAR Update Chapter 2) is acceptable as it is not required per RG 1.97 and does not impact the capabilities of RM-29. The rigging support will be seismically qualified to meet seismically induced systems interaction requirements. This design change does not affect Technical Specifications, Emergency or Security Plans, Effluents, Environmental Protection, Fire, or Quality Assurance Programs.

22. Connect PGA Panel Alarm and Condenser DP Signal to Control Room
DCP J-049218, Rev. 1 (Unit 1) (LBIE Log No. 96-038)

This design change replaced existing local condenser delta-P pressure indicators on the generator auxiliaries (PGA) panel with indicating transmitters. The transmitter signals are processed by a new local panel, PK011, and sent to the plant process computer (PPC). The PPC provides control room indication of the condenser delta-P signal and alarm capability to the main annunciator system (MAS). Individual alarm signals from the PGA panel were transmitted to the MAS by a new remote multiplexer in PK011.

Before the modification, individual PGA panel alarms and condenser DP indications were available only locally. A grouped alarm from the PGA panel was input to the MAS for display in the control room. On receiving the grouped alarm, an auxiliary operator was dispatched to identify the specific generator alarm. The associated delay could have led to a unit trip or generator damage.

The safety-related portion of the modification installed raceway supports in the auxiliary building.

Safety Evaluation Summary

The safety evaluation was performed because FSAR Update Section 3.10.2.9 described the MAS as seismically qualified. The new remote multiplexer does not require seismic qualification. Information provided to the control room by the nonsafety-related instrumentation in PK011 is not required for safe plant shutdown or to mitigate the effects of an accident. Isolation is provided where needed to prevent a failure in the multiplexer from degrading operation of the MAS, PPC, or main condenser. The FSAR Update was changed to clarify that the nonseismic portion of the MAS will not adversely affect operation of the seismic portion. Verification activities ensured that no rebar was cut or damaged due to addition of the raceway supports. Any penetrations violated for the pulling of cable were resealed per applicable DCPP procedures. There is no impact on the frequency or consequences of any accident or equipment malfunction. The PGA instruments are not part of any TS-required function; there is no impact on any TS safety margin.

23. Reclassify FCV-430, 461, 495, 496 & 601 to Allow Crediting Remote Operation
DCP J-049259, Rev. 0 (Unit 1) (LBIE Log No. 97-116)
DCP J-050259, Rev. 0 (Unit 2) (LBIE Log No.97-117)

This DCP upgrades the motor control loops for the subject valves from Design Class II to Design Class ID by recognizing that they were originally procured, installed, and maintained in accordance with Design Class ID requirements.

Safety Evaluation Summary

The 50.59 evaluation concluded that upgrading the design classification of these motor control loops for these valves does not impact how they will perform their safety function.

24. Addition of “GO” Pushbuttons to SSPS Safeguards Test Cabinets
DCP J-049298, Rev. 0 (Unit 1) (LBIE Log No. 96-021)
DCP J-050298, Rev. 0 (Unit 2) (LBIE Log No. 97-123)

This design change adds two “GO” push buttons to each of the safeguards test cabinets in the solid-state protection system. This allows testing the steam generator main feedwater supply valves FCV-510/1510, 520/1520, 530/1530, and 540/1540. This design change was implemented during the eighth refueling outages for Units 1 and 2.

Safety Evaluation Summary

The new test pushbuttons do not affect protection circuits. The indirect safety function of the pushbuttons only affects the testing should the pushbutton contact fail open. The added pushbuttons are Class I devices and are not

expected to contribute to the evaluated adverse condition. There is no change in the way the steam generator main feedwater supply/bypass valves operate. The change does not degrade or prevent feedwater isolation. Failure of the test pushbuttons does not affect normal or accident operation of the valves.

25. Modify SCMM Annunciator Alarm
DCP J-049302, Rev. 0 (Unit 1) (LBIE Log No. 96-001)

This change interlocks the sub-cooled margin monitor (SCMM) lo-margin alarm with an existing reactor power permissive, P-10, to maintain the alarm during the appropriate low power operation modes. This alleviates the nuisance alarm at normal power operational modes.

Safety Evaluation Summary

This design change adds another function associated with reactor power permissive P-10. This will result in a revision to FSAR Update Table 7.2-2, "Protection System Interlocks." This wiring change does not affect the Emergency Plan, nor does it affect the Security Plan. The design change will not impact the Technical Specifications. The applicable annunciator response procedure will no longer apply during normal plant operation modes above 10 percent reactor power. This design change will not result in a test, experiment, condition or configuration that will affect the operation of the plant.

26. Utilize Gamma-Metrics Post Accident Monitors as Alternate Source Ranges
DCP J-049320, Rev. 0 (Unit 1) (LBIE Log No. 97-033)

This design change added continuous visual indication in the control room for the post accident neutron flux monitors to be used as additional source range channels during Mode 6. The indication is provided by connecting an isolated output of the Gamma-Metrics monitors to the plant process computer. This change was implemented during the Unit 1 eighth refueling outage.

Safety Evaluation Summary

The Gamma-Metrics post-accident neutron monitors provide the same level of quality assurance, redundancy, and necessary display range as the normal source range monitors. Because they do not have alarm and audio circuit capability, one normal source range channel must remain operable. The additional channels are used for indication only during Mode 6. The additional channels provide no control or protective functions. Should either operable channel (i.e., normal source range or the Gamma-Metric channels) fail, the actions specified by Technical Specification 3.9.2 will be taken.

27. Replace Rod Insertion Recorder YR-412 With PPC Recorders
DCP J-049346, Rev. 0 (Unit 1) (LBIE Log No. 97-166)

Replace Class II rod insertion recorder (YR-412) with two new miniature recorders that will be used for a different function. The new miniature recorders (YR-800 and YR-801) will be electrically connected to the plant process computer and used as required by the operators. The new recorders will be installed at the same location as the old recorder on Control Console CC1. The function of the new recorders is Class II. This DCP will be implemented during the Unit 1 ninth refueling outage.

Safety Evaluation Summary

The associated instrument recorders and electrical components have a non-safety related function (Class II). The recorders are used for monitoring purposes only. They are not required for the safe shutdown of the plant. The new recorders will be mounted on Control Console CC1, which is a safety-related panel. The new recorders will be seismically mounted. These recorders do not have any impact on the rod control function and do not contribute to the effects of any inadvertent control rod bank withdrawal or control rod ejection.

28. Control Room Shift Foreman Workstation Modifications Phase 2
DCP J-049353, Rev. 0 (Unit 1) (LBIE Log No. 97-168)
DCP J-050353, Rev. 0 (Unit 2) (LBIE Log No. 97-169)

This modification installed a permanent workstation for the Shift Foreman in the Unit 1 main control room. The former Unit 1 Shift Foreman's office was modified to provide office space for the Shift Supervisor and the Assistant Shift Foreman. The permanent workstation in the primary control room area provides the Shift Foreman with a clear "command and control" presence in the main control room, with good visual and audible access to control room operators and contact with plant operation.

This modification addressed recent INPO and NRC criticism of the former Shift Foreman/Control Room arrangement. Previously, the on-duty Shift Foreman was located in an office area adjoining the main control room. That location met the requirement for being within the control room isolation boundary (Reference NUREG-0700, Rev. 0, Guideline 6.1.1.6.a), but did not provide the preferred "good visual and voice contact with the primary operational area." The new configuration enhanced the Shift Foreman's ability to oversee plant operations, and to maintain a more formal and professional atmosphere in the control room.

Safety Evaluation Summary

No plant equipment was modified, so that new or different accidents or malfunctions were not introduced, and the frequency of analyzed accidents was

not increased. There was no change to any Technical Specification safety margin. The modifications were performed with the plant at power. Most of the work was away from the control boards and outside the Control Operator area to reduce the possibility of distractions or accidental equipment actuations that could cause an accident or impair the ability of the operator to respond to an accident or event. During the modifications, the Shift Foreman was continuously provided with all information necessary to respond to plant evolutions or events so that the potential consequences were not affected.

Phase 1 of this work (DCP J-49351) temporarily relocated the Shift Foreman to the Shift Control Operator area. Control room drawings were relocated from the existing cabinet in the center aisle to an area behind the vertical boards. Access through the center aisle was restricted. These factors did not limit the ability of control room personnel to respond appropriately. The limited access areas of the control room were accessible as required. Drawing relocation caused no significant personnel response delay.

Phase 2 removed the temporary Shift Foreman workstation and installed the permanent workstation. The modification did not affect any systems, structures, or components that are relied upon to mitigate accidents. Improved physical presence enhanced the ability of the Shift Foreman to exercise command and control. The more formal and professional control room atmosphere strengthened the ability of the control room crew to respond to normal plant evolutions as well as to the potential accidents and events evaluated in the FSAR Update. The new workstation location did not significantly affect control room personnel access.

29. Replace RWST Range Code 6 Rosemount Level Transmitters
DCP J-049363, Rev. 0 (Unit 1) (LBIE Log No. 97-037)

This change will replace the existing 2-LT-920 & 921, Rosemount Model 1153HD6RC transmitters, with Rosemount Model 1153HD5RC transmitters. This change will decrease the instrument and channel uncertainty and increase the minimum indicated refueling water storage tank (RWST) volume at the low level alarm to greater than the 120,650 gallons of RWST volume assumed in Table 6.3-5 of the FSAR Update.

Safety Evaluation Summary

Increased accuracy of the RWST level instruments does not increase the probability of accidents. The Emergency Plan is not affected by the RWST accuracy. The accuracy of the new transmitters exceeds the minimum accuracy required by the Technical Specifications. The Security Plan is unaffected by the accuracy of these transmitters.

30. Safety Parameter Display System (SPDS) Replacement
DCP J-050123, Rev. 0 (Unit 2) (LBIE Log No. 96-035)

This modification removed and replaced the original Technical Support Center, Emergency Operations Facility (EOF) , and the control room emergency response facility data system (ERFDS)/ SPDS hardware supplied by Babcock & Wilcox (B&W) The original ERFDS functions are now divided between two systems:

- A new computer system provided by this design change provides color graphic SPDS displays

- The ERFDS "Data Recording and Recall" functions used for post-trip review are now performed by the Plant Process Computer (PPC)

The ERFDS was replaced to solve the following problems:

Software errors resulting from operational changes or latent software defects in the original B&W design required operators to implement workarounds due to errors in the critical safety function status tree displays. Such workarounds inhibit or adversely affect the operators' ability to respond effectively to an emergency or a plant transient situation. Hardware failures caused by aging and obsolete components occurred with sufficient frequency that system availability was being adversely affected. In many cases direct replacement parts were not available. The original SPDS was implemented in firmware. PG&E did not possess the development tools needed to make changes. Changes could be purchased only from the original vendor at substantial cost and long lead-time. Even minor changes such as scaling limits or engineering units required an expensive firmware replacement.

Safety Evaluation Summary

The SPDS, PPC, and EOF/TSC activities and functions cannot initiate any accidents or cause any equipment malfunctions or failures. Similarly, these activities and functions cannot affect any Technical Specification safety margins.

However, the SPDS provides information to control room, TSC, and EOF personnel to aid in the development of accident evaluations and responses, and in making decisions regarding protection of the health and safety of the public. If the SPDS displays do not accurately reflect the plant configuration, assessment and response functions by operations and management may be delayed or degraded. The replacement ERFDS/SPDS is designed to facilitate maintenance of its displays to maintain fidelity to an evolving plant configuration. Thus, increased consequences due to inaccurate SPDS displays are not a concern.

31. Connect Condenser Delta-P Signals and Main Generator Auxiliary Panel (PGA Panel) Alarms to the Control Room
DCP J-050218, Rev. 0 (Unit 2) (LBIE Log No. 97-136)

The purpose of this design change is twofold: (1) Permanently connect the condenser delta-P (DP) signals to the plant process computer (PPC) via a new remote multiplexer panel, PK011. By having the condenser DP signals in the control room on the PPC, operators can have early warning of an upward trend by using the PPCs variable alarm capability. (2) Connect the main generator auxiliary alarms (panel PGA) to the Control Room via the same remote multiplexer panel, PK011, used in Purpose 1. The existing Rochester alarm system in panel PGA is replaced with a Ronan supplied lampbox (PK21), which is driven by the main annunciator system (MAS) via isolated data links. The purpose is to provide the operators with individual alarms (vs grouped or general alarms) associated with the main generator in order to promote timely response to system troubles. In addition, the 20+ year old Rochester annunciator system is replaced.

Safety Evaluation Summary

The safety evaluation deals mainly with Purpose 2 above. The condenser DP connection to the control room (Purpose 1) did not require a revision to the FSAR Update. The connection of the PGA panel to the MAS required a clarification to the FSAR Update statement that the MAS is seismically qualified. This design change added a paragraph to the FSAR Update to clarify that the main generator alarms connected to the MAS via a remote multiplexer are not seismically qualified; however, these connections are isolated by qualified means. There is no failure mechanism of the data link, remote multiplexer, or remote visual annunciator drivers that can adversely impact the function of the MAS following an earthquake. The main generator alarms provided by the remote multiplexers are Design Class II and are not needed to maintain the plant in a safe shutdown condition or to mitigate the consequences of seismic events.

The existing text was clarified by making two additional minor changes that did not impact the conclusion: (1) The MAS is seismically qualified to remain functional after an earthquake. (2) The alarms associated with the main generator are not seismically qualified, but will not adversely impact the system function following an earthquake. The main generator alarms are not needed to mitigate the consequences of seismic events.

32. Modify SCMM Annunciator Alarm
DCP J-050302, Rev. 0 (Unit 2) (LBIE Log No. 96-002)

This change interlocks the subcooled margin monitor (SCMM) lo-margin alarm with an existing reactor power permissive, P-10, to maintain the alarm during the

appropriate operational modes, low power operations. This alleviates the nuisance alarm at normal power operational modes.

Safety Evaluation Summary

This design change adds another function associated with reactor power permissive P-10. This will result in a revision to the FSAR Update Table 7.2-2, Protection System Interlocks. This wiring change does not affect the Emergency Plan, or the Security Plan. The design change will not impact the Technical Specifications. The applicable annunciator response procedure will no longer apply during normal plant operation modes above 10 percent reactor power. This design change will not result in a test, experiment, condition or configuration that will affect the operation of the plant.

33. Replace RWST Range Code 6 Rosemount Level Transmitters
DCP J-050363, Rev. 0 (Unit 2) (LBIE Log No. 97-036)

This change will replace the existing 2-LT-920 & 921, Rosemount Model 1153HD6RC transmitters, with Rosemount Model 1153HD5RC transmitters. This change will decrease the instrument and channel uncertainty and increase the minimum indicated refueling water storage tank (RWST) volume at the low level alarm to greater than the 120,650 gallons of RWST volume assumed in Table 6.3-5 of the FSAR Update.

Safety Evaluation Summary

Increased accuracy of the RWST level instruments does not increase the probability of accidents. The Emergency Plan is not affected by the RWST accuracy. The accuracy of the new transmitters exceeds the minimum accuracy required by the Technical Specifications. The Security Plan is unaffected by the accuracy of these transmitters.

34. Canopy Seal Clamp Assemblies at Spare CRDM Nozzles
MMP M000036-1, Rev. 1 (Unit 2) (LBIE Log No. 98-028)

This Maintenance Modification Package (MMP) is created to allow for installation of canopy seal clamp assemblies (CSCAs) and dummy can adapters onto canopy seal welds on the reactor vessel closure head CRDM penetrations. The CSCAs are designed to encapsulate defective canopy seal welds, functioning as an additional barrier to prevent migration of reactor coolant from a weld defect onto the carbon steel reactor vessel closure head.

Safety Evaluation Summary

The CSCAs are safety-related components that are designed and fabricated for reactor coolant system pressure, temperature and loading conditions in

accordance with applicable ASME Codes, and interfacing instructions for the CRDM nozzles. Installation of the CSCAs will be in accordance with DCPP's ASME Section XI Program Plan and controlled with approved plant maintenance procedures.

The CSCA serves as a backup device to prevent the leakage of reactor coolant through a defective canopy seal weld from corroding the carbon steel reactor vessel closure head. In this capacity, the CSCA functions to reduce leakage from the defective canopy seal weld and thus prevent the leakage from increasing. Leakage, if present, from the CSCA will be detected by the leakage detection method. Any leakage attributed to the clamp will be classified as "unidentified" to which a 1 gpm limit required by the Technical Specifications will apply. Therefore, there is no reduction in the margin of safety as defined in the basis for any Technical Specification.

35. Steam Generator Mechanical Plugging
MMP M000043-1, Rev. 2 (Units 1 & 2) (LBIE Log No. 98-021)

This change authorizes the mechanical plugging of steam generator tubes that have been identified for removal from service as a result of tube inspections. The repair consists of installing erosion/corrosion resistant mechanical rolled plugs at the steam generator tubesheet.

Safety Evaluation Summary

The integrity of the reactor coolant system (RCS) and of the steam generators is maintained by the installation of these plugs. There is no change in design or functions of the steam generators. The integrity of the plugs is assured by the qualification of the process used to install the plugs and by evaluations to confirm the design will perform the intended function. Similar mechanical plugs are already in service in the steam generators.

The plugs are installed in a way compatible with the overall integrity of the tubesheet. These modifications only affect localized passive structural components. This change does not authorize the removal and plugging of tubes in excess of the present limit of 15 percent of the plugged steam generator tubes. This change does not result in a reduction in the margin of safety as defined in the Technical Specification bases.

36. Installation of Framatome Weld Plugs in Steam Generator Tubes
MMP M000044-1, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-076)

This design change allows installation of Framatome weld plugs in defective steam generator tubes at DCPP Units 1 and 2.

Safety Evaluation Summary

Installation of a welded plug to remove defective tubes from service maintains the integrity of the reactor coolant pressure boundary for all normal and postulated accident conditions. The weld plug material and weld filler material used for installation are compatible with the tube/tubesheet and are not susceptible to degradation that caused the tube to become defective.

37. Steam Generator Tube Pull (FTI)
MMP M000055-1, Rev. 1 (Units 1 & 2) (LBIE Log No. 98-022)

This change authorizes the removal of steam generator (SG) tubes from each of the SGs. The removed SG tubes will provide samples for visual inspection as well as provide samples for laboratory examination and analysis which can aid in better understanding of tube degradation and failure mechanisms. Also, the results will provide a direct correlation between the indications and eddy current test results.

Safety Evaluation Summary

The process employed to remove the tube segments is designed and procedurally controlled to prevent contact with adjacent tubes. Further, the tube remnants remaining in the SG have been analyzed to show that no compromising contacts with adjacent tubes will occur during normal operations and accident conditions. With removal and plugging of some tubes per this MMP, the total number of plugged tubes in the SGs will still be a small fraction of the total tubes.

The removal of flow area by plugging still maintains the circulation capability of the loops well above that required and/or assumed in plant analyses. This change does not compromise the operability of the SGs including the flow and heat transfer capability and pressure boundary integrity during normal operation and postulated accidents. Therefore, this change does not result in a reduction in the margin of safety as defined in the Technical Specification bases.

38. Installation of Framatome U-Bend Stabilizer in Steam Generator Tubes
MMP M000057-1, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-090)

This design change allows installation of Framatome U-bend stabilizers in defective steam generator (SG) tubes requiring stabilization.

Safety Evaluation Summary

Installation of Framatome U-bend stabilizers in defective SG tubes, in conjunction with tube plugging, maintains adjacent SG tube structural and leakage integrity by preventing damage to adjacent tubes during normal and

accident flow induced vibration loading. Stabilization prevents the possibility of a tube section becoming a loose part in the secondary system. The integrity of the tube plugs is maintained. The stabilizer material is not susceptible to degradation.

39. Determinate Defective Pressurizer Heaters
MMP M000058, Rev. 2 (Unit 1) (LBIE Log No. 97-197)
MMP M000058, Rev. 1 (Unit 1) (LBIE Log No. 97-027)
MMP M000059, Rev. 2 (Unit 2) (LBIE Log No. 97-198)

This Maintenance Modification Package (MMP) allows pressurizer heaters that have failed to be disconnected. This allows other heaters that are fed from the same circuit breaker to be returned to service. The initial pressurizer heater capacity was 1800 kW. This MMP allows failed heaters to be disconnected as long as the connected capacity is at least 1340 kW with Heater Groups 1 and 4 each having at least 276 kW connected and Groups 3 and 4 each having at least 345 kW connected.

Safety Evaluation Summary

The pressurizer heaters are nonsafety-related. The purpose of the pressurizer heaters is to control pressurizer pressure during heat up and power operation and to support natural circulation of the reactor coolant system during the loss of offsite power. 150 kW is required to support natural circulation. Technical Specifications define the minimum pressurizer heater capacity as 150 kW from two groups which can be supplied by vital emergency power. This MMP maintains this 150 kW by limiting the number of heaters that can be disconnected. Therefore, all margins of safety implicit in this Technical Specification requirement are maintained by this MMP.

40. Replace 4-kv Potential Transformer Primary Fuse
MMP M000066-1, Rev. 1 (Unit 2) (LBIE Log No. 98-012)

Licensee Event Report (LER) 1-97-010-01, “Unplanned Start of Diesel Generator 1-1 Due to a 4160-V Bus H Startup Feeder Phase Potential Transformer Opened Fuse,” discusses the event, root cause and possible upgrade of the primary fuse from 1/2 ampere to 1 ampere. Maintenance Modification Package M000066, Rev.1, allows the replacement of Units 1 and 2, 4 kV vital and nonvital potential transformer primary fuses. The replacement fuses have a 1 ampere current rating in place of the existing 1/2 ampere rating. While the 1/2 ampere rating is acceptable, the 1 ampere rating increases the inrush current margin to allow more reliable operation. The replacement fuses have the same physical characteristics as the existing fuses.

Safety Evaluation Summary

The plant configuration and operational logic remains unchanged.
The failure analysis concluded that the most likely cause of failure was accumulated fuse element degradation due to current surges on the fuse over the life of the plant. Increasing the replacement fuse inrush capability implements the analysis recommendation. The safety function of the 4-kV potential transformer is to provide a signal, for control and instrumentation, which is proportional to the voltage of the bus or feeder. The safety function of the primary fuse is to carry load/inrush current and provide short circuit protection to the potential transformer.

The replacement fuse maintains coordination with existing fuses and relays, is safety related, and meets the requirements of PG&E Design Class I and IEEE 308 Class IE. Since the 1 ampere replacement fuse has three times the inrush capability of the 1/2 ampere existing fuse, the probability of occurrence of a fuse blow malfunction during operational transients is decreased, and the availability of potential transformers to perform safety related instrumentation and control functions is increased. The 4-kV primary fuse has no effect on any radiation barrier or offsite dose..

41. Replacement of Diesel Fuel Oil Tank 0-1
DCP M-049160, Rev. 0 (Units 1 & 2) (LBIE Log No. 96-004)

This modification consists of replacing the 40,000 gal. single-walled diesel generator fuel oil tank 0-1 and associated piping up to the pump vaults with a new 50,000 gal. double walled tank and new piping. The design change package also installed a leak detection system for the tank and piping. The overall function of the tank and piping remained the same. The purpose for the replacement was to meet the new California Code of Regulations.

Safety Evaluation Summary

The removal of one of the two diesel fuel oil storage tanks from service has been reviewed by the NRC. To permit replacement of the tanks, the NRC has issued License Amendments 108 and 109 to permit operation of the plant for up to 120 days with a single operable diesel fuel oil tank. The fuel supply to each of the diesel generators is being preserved for the duration of the construction activities required to implement the design change. Construction procedures and work plans assure that the function of the 0-2 diesel fuel oil supply system and the capability of performing that function are not altered during the diesel fuel oil tank 0-1 replacement activities. The final configuration of the diesel fuel oil system following the implementation of the design change assures that the system design, function, and method of performing its function are unchanged or enhanced.

42. Requalification of the CCWS for a Maximum CCW Post-Accident Supply Temperature of 140°F
DCP M-049291, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-158)
DCP M-049291, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-077)

This design change package (DCP) established a new postaccident temperature limit profile for the component cooling water system (CCWS). This was achieved by upgrading individual components' temperature qualifications where necessary and revising the associated design and licensing documentation. This DCP was performed to document previously unrecognized margin between the postaccident CCW supply temperature profile and the documented CCWS equipment temperature limitations.

Safety Evaluation Summary

The bases for the 50.59 conclusions are (1) that raising the qualified post-accident system temperature limit does not effect how the system will actually respond to an accident, and (2) the new elevated temperature limits do not affect the capability any CCW (or related system) equipment to perform its safety function.

43. Removal of Halon from SSPS Rooms
DCP M-049295, Rev. 0 (Unit 1) (LBIE Log No. 96-010)
DCP M-050925 Rev. 0 (Unit 2) (LBIE Log No. 96-011)

These design changes removed the Halon fire suppression system from the Unit 1 and Unit 2 solid-state protection system (SSPS) rooms. It was difficult to maintain the leak-tightness of the ceiling of these rooms as required to maintain the Halon concentration in the event of a fire. In addition, the release of Halon to the atmosphere has adverse environmental consequences, and it is no longer commercially available. Since the system is not required to satisfy Appendix R safe shutdown requirements, it was not replaced with an alternative fire suppression system. However, the existing fire detection system and alarms were left in place.

Safety Evaluation Summary

The absence of the Halon system has no effect on the probability of a fire occurring in the SSPS rooms. The removal of the system does not increase the analyzed consequences of a fire in the SSPS rooms because the current analysis assumes the loss of an SSPS train as a result of a fire. Removal of the Halon suppression system does not impact the ability to achieve and maintain safe shutdown of the plant; once the reactor is tripped, the equipment in the SSPS room is no longer required to maintain safe shutdown. Manual actions and redundant safe shutdown components, not the Halon system, are credited for mitigating the effects of a fire in this area. The operation of the SSPS

computers will not be affected by the change, and the consequences of a fire in this area are unchanged from those already evaluated.

44. CCP 1-1 and 1-2 Gear Oil Cooler Replacement
DCP M-049312, Rev. 0 (Unit 1) (LBIE Log No. 96-014)
DCP M-050312, Rev. 0 (Unit 2) (LBIE Log No. 96-015)

This design change installed new centrifugal charging pump (CCP) gear oil coolers on the 1-1 and 1-2 CCPs to enhance heat transfer and raise temperature qualification.

Safety Evaluation Summary

This 50.59 evaluation concludes that there is no unreviewed safety question concerning replacement of the coolers. This conclusion is reached because (1) the coolers transfer as much (or more) heat from the CCP gear oil, enhancing the CCP's ability to perform its design function, and (2) the coolers are installed in the same configuration and to the same design qualification as the previous coolers.

45. CCW-1-TCV-130 Replacement (HOT TAP)
DCP M049319 (Units 1 & 2) (LBIE Log No. 97-089)

See LBIE 97-046 (Procedure MP I-38-M.1, Units 1 & 2, Rev.0 in "Procedures" section of report). This was a revision to LBIE Log No. 97-046 that changed the mode that work could be conducted. The mode was change from 0 to Modes 5, 6, or 0.

Safety Evaluation Summary

This change only applies to Mode 6 with fuel removed from the reactor vessel. Therefore, because the reactor coolant system is still depressurized, there is no possibility the change involves an unreviewed safety question (see LBIE Log No. 97-046).

46. Revise Design Basis for ASW Pump Motors
DCP M-049385, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-137)

In 1988, the auxiliary saltwater (ASW) pump impellers were replaced with those of larger diameter under Design Change Package (DCP) M-39834. The increase in impeller size has caused the pump motor to operate beyond its nameplate rating (400 hp). This condition (450 hp) of operation was evaluated by plant engineering and accepted. Based on a subsequent engineering Calculation M-854 and its supporting test data, the power supplied by the motor, while operating in a single pump/two heat exchanger configuration, can be as high as 465 hp (conservatism included).

PG&E electrical engineering and Westinghouse (the motor manufacturer) has evaluated that the motors are capable of operating at 465 hp without exceeding their design limits. This evaluation was documented in two engineering memos and a Westinghouse letter. DCP M-049385 is used to accept the extended rating (465 hp) as the new limit for the ASW pump motor operation and to revise the Design Criteria Memorandum S-17B, as well as the FSAR Update sections.

Safety Evaluation Summary

There are no known impacts on the equipment important to safety for accident events due to the ASW pump motor operating in a higher rating up to 465 hp. The increase in ASW pump motor hp can cause a higher consumption in diesel fuel and can affect the adequacy of diesel fuel inventory. Such impacts have been evaluated in engineering Calculation M-786, Rev. 8, and the new hp rating (465 hp) has been used to establish the minimum required fuel storage to meet the license bases.

The increase in ASW pump motor hp may affect diesel loading and loading sequence, motor protective relay setpoints, feeder cable ampacity and voltage drop, and the motor stator temperature rise. These issues have been addressed by electrical engineering and Westinghouse (the motor manufacturer) and concluded that the ASW motors are capable of operating at 465 hp without exceeding the design limits for the motors and the diesel generators. This evaluation was documented in engineering memos. The increase in ASW pump motor hp will affect the internal thermal load for the pump vaults. This increase has been analyzed by engineering and documented in HVAC Calculation 82-6, Rev. 5. Therefore, the probability of a malfunction of equipment important to safety previously evaluated in the FSAR Update will not be increased.

47. Revised Peak CCW Temperature Following a Design Basis Accident
DCP M-049386, (Units 1 & 2) (LBIE Log No. 98-070)

The limiting component cooling water (CCW) temperature transients following a design basis accident (DBA) have been reevaluated by Westinghouse in WCAP-14282, Revision 1, dated December 1997. Revised WCAP-14282 captures previous CCW heatup evaluations contained in several documents and incorporates the latest design input while using the same methodology used in past analyses.

Safety Evaluation Summary

The evaluation specifically addressed the following topics: (1) incorporation of WCAP-14282, Rev. 1, into the licensing and design bases, (2) establishment of an elevated ultimate heat sink temperature limit of 70°F, (3) revision of the normal maximum operating CCW temperature from 120°F to 80°F for Modes 1-3

and 95°F for Modes 4-5, (4) a revised bases for operation of two RHR trains of CCW/ASW in the cold leg recirculation phase, (5) a revised bases for the CCW heat exchanger saltwater inlet valve (1/2-FCV-602 and -603) required 8-hour hold time, and (6) clarification that during post-LOCA split-train operation, operator action is required to recover from specific active failure scenarios. None of these topics involve physical changes to the plant. The evaluation concluded that the proposed changes do not involve an unreviewed safety question.

48. EDG Rooms - CO_2 Manual Actuation Switches: Relocation
DCP M-050366, Rev. 0 (Unit 2) (LBIE Log No. 97-186)

The emergency diesel generator CO_2 manual actuation switches were moved from the south wall of the turbine building to a location outside the diesel generator rooms in the corridor. The relocation was required because the switches were originally located in Pyrocrete boxes that did not conform to a tested configuration. Offsite power circuits were located in vicinity of the switches. A fire in the turbine building had the potential to disable the diesel generators and damage the offsite power circuits.

Safety Evaluation Summary

This 10 CFR 50.59 safety evaluation was performed because FSAR Update Chapter 9, Appendix 9.5A, specifically stated that the switches are located in Fire Zone 19-A, and are enclosed in Pyrocrete to prevent hot shorts. The switch relocation affected the description of Fire Zone 19-A. Ability to achieve and maintain safe shutdown depends on availability of power to the equipment required for safe shutdown. Relocating the CO_2 manual actuation switches provides increased protection because the switches are now separated from a fire in the turbine building by 2-hour fire barriers. The CO_2 manual actuation switches are not associated with initiation of any accident. The increased separation from potential turbine building fires enhances the ability to protect the diesel generators and reduces the potential for hot shorts to impair operation of the diesel generators. Probability and consequences of accidents or equipment malfunctions are not increased.

49. Convert CCP 1-1 to 3rd Generation Seal Configuration
DCP N-049231, Rev. 0 (Unit 1) (LBIE Log No. 96-016)

The DCP changed/replaced the pump case and internal assembly for Centrifugal Charging Pump (CCP) 1-1 with a like-for-like pump case and internal assembly that has been equipped with the 3rd generation seal configuration. The old seal design (first generation) was a multicomponent assembly requiring external cooling by CCW. Although no known problem is associated with maintenance at DCPP for the 1st generation seals, the conversion to 3rd generation was done as an enhancement, which could increase pump availability.

Safety Evaluation Summary

The replacement of CCP 1-1 with the pump casing and internal assembly from CCP 2-1 is considered a like-for-like replacement. The capability of the CVCS system to meet the functional requirements of the accident analysis is unaffected by this change.

The new 3rd generation mechanical seals meet or exceed the original mechanical seal requirements, with the exception that external cooling is not required. Seal life is extended as a result of the one piece seal sleeve/ pumping ring design. Therefore, the availability of the CCP is increased. Also, because CCW is no longer required for cooling, one of the failure modes that can cause unavailability of the CCP is eliminated.

50. Installation of FE-999
DCP N-049364, Rev. 0 (Unit 1) (LBIE Log No. 97-031)
DCP N-050364, Rev. 0 (Unit 2) (LBIE Log No. 97-032)

This DCP installs a new flow element, FE-999, in the charging injection flowpath downstream of existing FE-917. This was done because of the non-ASME standard installation of FE-917 which is documented in AR A0414083. The effect of this nonstandard installation is such that the bias corrections that would be necessary to correct the reading from FE-917 would restrict the allowable range of settings during the ECCS flow balancing of STP V-15.

Safety Evaluation Summary

While the new flow element will provide a minor restriction to the flow in the charging injection header, it is not the most limiting restriction in the line. Adequate flow is verified by testing each outage by STP V-15.

NDE inspections were performed for the welds on the piping and fittings to assure installation in compliance with applicable construction codes. Testing is performed each outage for injection flow balancing and post loss-of-coolant accident recirculation leakage. All applicable design and licensing standards for the piping and components were complied with to assure all requirements were met in the installation.

Therefore, the installation of this additional flow orifice did not affect the probability or consequences of any accident, new or previously reviewed, nor did it affect the basis for any Technical Specification. There is no affect on the licensing basis of the plant.

51. Gross Failed Fuel Detector Removal (Note: This design change has not been implemented)
DCP N-049369, Rev. 0 (Unit 1) (LBIE Log No. 97-167)
DCP N-050369, Rev. 0 (Unit 2) (LBIE Log No. 97-203)

This design change deletes the gross failed fuel detector (GFFD) system from the NSSS system. The GFFD process skid, and GFFD control console instrumentation will be physically removed. In addition, component cooling water piping, sample tubing, and associated supports will be modified accordingly. This design also includes electrical changes to the GFFD control console and skid power supply and signal wiring. The GFFD control console will remain in-place as it houses main steam line radiation monitors and loose parts monitor pinger circuits.

Safety Evaluation Summary

The GFFD system is not related to any accident previously evaluated in the FSAR Update. The GFFD is a nonsafety-related device, originally designed to monitor reactor coolant during normal operation (for purposes of detecting potential fuel defects). The GFFD provides no accident monitoring function and removal of the GFFD will not affect the capability to obtain a post-accident reactor coolant sample. Process line changes resulting from the GFFD removal are designed to assure leak-tight integrity of the sampling system tubing, and the tubing will continue to be seismically supported to meet system post-HOSGRI cold shutdown requirements. The supply/return piping to the GFFD sample cooler has been redesigned to ensure CCW header “C” efficiencies are not adversely impacted, and the associated piping will continue to be seismically supported. Design changes to the GFFD control console have been seismically qualified to maintain integrity of the main steam line radiation monitors (which are housed within the GFFD control console) and adjacent inter-linked cabinets.

There is no Technical Specification (TS) requirement to provide for continuous on-line sampling of reactor coolant for purposes of assessing core conditions during normal power operation. Currently, reactor coolant sampling is performed on a batch basis, thus meeting the sampling frequency requirements of TS 3.4.8 (RCS specific activity). Frequent TS-required grab sampling will continue to be performed for failed fuel detection. Note that DCPP continues to search for an instrument to detect for severe failed fuel failures in accordance with Safety Evaluation Report Supplement 6. Therefore, elimination of the GFFD system, considering the existing sampling program, will not result in any margin of safety reduction.

52. Install Zinc Injection Subsystem
DCP N-049408, Rev. 1 (Units 1 & 2) (LBIE Log No. 98-069)
DCP N-049408 (Units 1 & 2) (LBIE Log No. 98-025)

Install a skid-mounted, zinc acetate injection subsystem designed to inject zinc into the reactor coolant system (RCS) to inhibit stress corrosion cracking in the Alloy 600 steam generator tubes.

Safety Evaluation Summary

This design change installs equipment to inject zinc into the RCS. The new equipment has no impact on any FSAR Update accidents. With regard to boron dilution, the limited capacity of the zinc injection pumps (less than 2 gallons per hour) is insignificant when compared with the 262 gpm dilution flow considered in the uncontrolled boron dilution accident at power. The zinc injection equipment will not interact with or impact the operation of any equipment important to safety. Therefore, it is concluded that no unreviewed safety question is involved.

53. Design Criteria for CVCS Evaporator Feed Demineralizers Resin Loading
DCP N-049429, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-045)

This design change revises the design criteria for the chemical and volume control system (CVCS) evaporator feed demineralizers to allow variation of the combination of anion and cation resin used in the demineralizers to optimize operation.

Safety Evaluation Summary

The proposed changes in resin loading have no effect on accidents analyzed in the FSAR Update and do not impact operation of equipment important to safety. Therefore, it is concluded that no unreviewed safety question is involved.

54. ECCS Pressure Reducing Orifice
DCP N-050286, (Unit 2) (LBIE Log No. 98-006)
DCP N-050286, Rev. 0 (Unit 2) (LBIE Log No. 97-152)

This DCP modified both the charging and safety injection lines of the emergency core cooling system (ECCS). A pressure reducing orifice assembly and trimming orifice were installed in each charging injection line. The charging injection throttle valves 8810A-D, flow orifices (FE 924-927), interconnecting piping, and orifice flanges were replaced. In each safety injection cold leg, a pressure reducing orifice assembly was installed and the flow orifices (FE 974-977) were replaced.

Safety Evaluation Summary

The addition of pressure reducing orifice assemblies and trimming orifices coupled with the replacement of the charging throttle valves, flow elements, and orifice flanges is to prevent pump runout of centrifugal charging pumps (CCPs) and safety injection pumps (SIPs), as well as to avoid potential ECCS flow

blockage during the sump recirculation phases. The ECCS delivers flow to the reactor vessel for core cooling and to provide additional shutdown capability following an accident. The ECCS performance is evaluated by using the minimum and maximum pump curves coupled with the maximum and minimum system resistances, which results in the minimum and maximum ECCS injection profiles. System resistance provided by the ECCS throttle valves in each injection line minimizes the spill flow through the broken line and prevents pump runout during a postulated LOCA. The addition of passive pressure reducing orifice assemblies and passive trimming orifices results in distribution of the system resistance previously provided by the single throttle valve. The replacement of charging injection throttle valves and flow elements provides an enhanced design of the existing components.

Since ECCS is not considered an accident initiator and the addition of the passive components does not create new failure modes, this modification does not impact the possibility of an accident nor the consequence of an accident as previously evaluated in the FSAR Update. The addition of the passive components to share the system resistance does not reduce the margin of safety as defined in the basis for any Technical Specification.

55. <u>21-Month Cycle, Unit 2 Cycle 8</u>
DCP N-050382, Rev. 0 (Unit 2) (LBIE Log No. 97-163)

This design change authorized the extension of Unit 2 Cycle 8 from 18 months nominal to 21 months nominal.

Safety Evaluation Summary

The LBIE for this design change reviewed the following items:

- The use of 1.25 grace period for the not yet surveillance test procedures affected by the approved License Amendment Requests 95-07, 96-10, 97-01, and 97-07
- Changes to instrument setpoint and postaccident monitoring calculations
- Design change notice for changing the pressurizer level high trip setpoint
- Evaluation of steam generator tube integrity
- Impact on major plant systems and components
- Changes to DCMs and FSAR Update
- Effect on Emergency Plan

Based on this review, there were no 10 CFR 50.59 safety issues or unreviewed safety questions identified.

56. Replace Containment Recirculation Sump Screen
DCP N-049317, Rev. 1 (Unit 1) (LBIE Log No. 97-084)

This DCP modifies the Unit 1 outer containment recirculation sump screen (top, sides, and front inclined sections) by replacing the existing mesh with a 1/8-in. mesh opening. This modification is necessary because DCPP has the potential to pass debris through the sump screen that could potentially block flow through the safety injection to cold leg and charging injection to cold leg throttle/runout valves during the recirculation phase of a loss-of-coolant accident (LOCA).

Safety Evaluation Summary

Rescreening with a smaller mesh size will improve the sump's capability to filter out debris, and when combined with another modification to increase the minimum opening in the ECCS injection lines, the possibility of ECCS flow blockage will be minimized. The sump's function of providing a source of long-term cooling water following a LOCA is not compromised for the following reasons: the sump's structural and seismic integrity is maintained, the required free flow area is maintained under minimum LOCA water level and debris blockage conditions, adequate RHR pump NPSH is maintained, vortex suppression is maintained, no new seismically induced system interaction or high energy line break concerns are created, material selection maintains

structural/ functional integrity under all conditions, and the new design does not interfere with the sump level instrumentation.

57. Unit 1 Cycle 9 Reactor Core Reload
DCP N-49368, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-081)

This design change authorized the reloading of the Unit 1 core in a specific pattern of new and partially spent fuel, which is known as the Cycle 9 reload core.

Safety Evaluation Summary

The LBIE for this design change relies, in part, on information provided by the Westinghouse Reload Safety Evaluation that is specific for the core design of Unit 1 Cycle 9. There is no change from previous core designs that triggered the need for prior licensing review. Based on a review of the FSAR Update and associated Chapter 15 accident analysis, there were no 10 CFR 50.59 safety issues or unreviewed safety questions identified.

58. Unit 2 Cycle 9 Reactor Core Fuel Load
DCP N-050368, Rev. 0 (Unit 2) (LBIE Log No. 98-024)

This design change incorporates the new core design from Westinghouse for operation of Unit 2 Cycle 9. This is done routinely for each reload cycle since cores eventually become less reactive and need the addition of new fuel to start a new cycle.

Safety Evaluation Summary

The fabricator provided a 10 CFR 50.59 safety evaluation that verified there are no impacts to the reference safety analyses in the FSAR Update, no unreviewed safety questions, and no impacts on the plant Technical Specifications. This core design meets all the design criteria for maintaining its design basis function. The features implemented in this design are similar to those implemented in previous cores.

59. Unit 2 Overpressurization Protection of Penetrations 49 and 50
DCP P-050371, Rev. 0 (Unit 2) (LBIE Log No. 97-156)

This plant modification added holes to the upstream side of the inner containment isolation ball valves in the liquid radwaste system on containment penetrations 49 and 50. This change protects the integrity of the isolated penetrations against failure in the event a design basis accident were to cause heating, expansion, and pressurization of the fluid trapped between the isolation valves. The change also provides a rupture disc upstream of the valve on penetration 50 to ensure a lower pressure relief path is available during a design

basis accident. This change is in response to evaluation of the concerns of Generic Letter (GL) 96-06.

Safety Evaluation Summary

The change is necessary and capable of ensuring the containment isolation system will meet its design and license basis requirements in the event of a design basis accident as detailed by GL 96-06. That is, the change must be implemented to ensure the penetration is not overpressurized due to expansion of the trapped fluid during a design basis accident.

No new containment isolation failure modes were introduced by the change and the designed failure of the rupture disc in the event of a design basis accident will not affect the consequences of the event. Further, the design and procurement quality of the rupture disc ensure that its failure and the subsequent radwaste spill inside containment would not occur for the range of radwaste system operating conditions.

60. Manipulator Crane Parking Position Limitation
DCM S-42B (Units 1 & 2) (LBIE Log No. 97-054)

This evaluation considers the movement of the manipulator crane from its eastmost position over the refueling cavity during operating Modes 1 through 5. Hosgri correspondence to the NRC stated that the crane would be “parked at east end of its travel during this mode (power operation to cold shutdown).” The Hosgri Report states that the crane will not be used in Modes 1 through 5. The capability to move the crane during these modes is necessary to facilitate preventative maintenance and testing of the crane itself or to allow access to structures, systems, or components adjacent to but blocked by the crane (e.g., hatches, lower cavity area, fuel transfer system upender, and cart winches).

Safety Evaluation Summary

The manipulator crane and its support rails remain qualified for Hosgri independent of the parked position of the crane. Civil Engineering has evaluated the crane and containment for seismic and seismically induced system interaction (SISI) effects and have concluded that the configuration is acceptable provided the crane is not parked closer than 5 feet to structures, systems, and components in its travel path. The SISI spacing criterion described above would assure that the manipulator crane would not strike these components, thereby precluding secondary interactions.

61. Avoidance of Unnecessary Thermal Transients on Alternate Charging Nozzle
DCM S-8, Rev. 6 (Units 1 & 2) (LBIE Log No. 97-128)

This change adds a new entry in the Precautions and Limitations section of the chemical and volume control system design basis document to reflect the Westinghouse recommendation that use of alternate charging be minimized during normal power operation to avoid unnecessary thermal transients on the alternate charging nozzle, and to state that, on this basis, the Inservice Test Program stroke testing of normal charging line Valves 8146 and 8147 should be performed on a cold shutdown frequency rather than quarterly. Excessive use of alternate charging could contribute to eventual fatigue failure of the alternate charging nozzle, resulting in a loss-of-coolant accident.

Safety Evaluation Summary

The normal charging flow path on which these air-operated, fail-open valves are located is isolated by a safety injection signal, so the postaccident position of these valves is inconsequential for purposes of accident mitigation. Hence, the stroke times of these valves has no effect on the consequences of an accident.

B. Temporary Modifications, Electrical Jumpers and Lifted Leads, Mechanical Jumpers and Bypasses, and Test Equipment

1. Jumper to Provide Non-1E Power to ABVS Supply Fan, S-32,Rev. 0, Rev. 1, and Rev. 2
(Unit 1) (LBIE Log No. 97-094)

This LBIE evaluates the activity of installing a jumper to allow the operation of the auxiliary building ventilation system (ABVS) Supply Fan S-32 from a nonvital electrical bus during the Unit 1 eighth refueling outage. Fan S-32 provides ventilation cooling air to rooms housing emergency core cooling system (ECCS) components in the auxiliary building. Normally, Fan S-32 is powered by vital Bus H, which would not be available. The redundant supply Fan S-31 was also not available due to the outage of Bus F. This jumper was applicable during Modes 5 and 6. Technical Specification 3/4.7.6 requires the ABVS to be operable in Modes 1 through 4 to ensure that radioactive materials leaking from the ECCS equipment within the auxiliary building following a LOCA are filtered prior to reaching the environment . The ABVS also has the support function to provide ventilation cooling to the areas containing safety-related equipment that is required to be operable to mitigate the consequences of certain design bases accidents and to provide safe shutdown . During defueled condition, Mode 6 or Mode 5, the ABVS has a support function to provide cooling air to the engineered safety features (ESF) equipment rooms served by the ABVS. The installed jumper would allow the ABVS to provide sufficient cooling to the ESF equipment rooms as required during the applicable modes. This jumper was issued as Rev. 0, Rev. 1, and Rev. 2. Only Rev. 2 was installed.

Safety Evaluation Summary

The jumper allowed the ABVS to perform its support function of providing ventilation cooling function to the ESF equipment. The jumper was adequately sized for the expected fan motor loads. In this configuration, Supply Fan S-32 would supply the design bases air flow required to maintain the ESF equipment at their normal operation temperature. The ambient room temperature of the ESF pump rooms (SI, CCW, RHR, charging, and containment spray) in the auxiliary building are monitored. If failure of the non-vital power supply occurred, the pumps would remain operable until the temperature increased to 30°F above the limits stated in Equipment Control Guideline (ECG) 23.1 (133°F for charging and RHR, 141°F for CCW). If the room temperatures reached these limits, corrective actions to provide adequate cooling would be taken to restore room temperature to within limits within the allotted 4-hour limiting condition for operation (LCO). The actions would consist of opening doors or installing a readily available gas-powered temporary power supply and portable fans to direct cooling air to the affected areas. Exceeding the monitored temperature limits does not mean that the equipment will fail, but only that an analysis would be required to evaluate the impact of the higher temperature had on the

operating life of the equipment. Thus, this jumper will not cause the malfunction of equipment important to safety.

2. TSR-98-036 Lead Shielding Request per Procedure RP1.ID2
(Unit 2) (LBIE Log No. 98-015)

This temporayr modification allowed installation and removal of temporary lead shielding on Unit 2 Lines 508, 509, and 927, located above the residual heat removal (RHR) sump in containment. The shielding will be installed in Modes 5 and 6 only and removed prior to entering Mode 4. The shielding will be installed on operable piping which creates a condition that might affect safe operation of the plant not evaluated in the FSAR Update.

Safety Evaluation Summary

The only Mode 5 and 6 accident analyzed in the FSAR Update is a fuel handling accident. The addition of lead shielding onto an operating residual heat removal line does not affect this accident. The blankets' tie-down arrangement is considered structurally adequate such that it will not fail during a seismic event and damage any seismically induced systems interaction targets in the vicinity. Additional weight of the blankets has been evaluated for its impact on the seismic qualifications of piping and found to be acceptable. Based on the above criteria and justification, an unreviewed safety question is not involved.

3. EDG 1-2 Lube Oil Heater-Jumper No. 1-97-012 Alternate Power Supply During 1R8-Bus F Clearance
Jumper 1-97-012, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-048)
Jumper 1-97-013, Rev. 0 (Units 1 & 2) - Bus G (LBIE Log No. 97-047)
Jumper 1-97-015, Rev. 0 (Units 1 & 2) - Bus H (LBIE Log No. 97-049)

This jumper permits emergency diesel generator (EDG) 1-3 lube oil heater to be energized from another power source during the Unit 1 eighth refueling outage for the Bus H clearance.

Safety Evaluation Summary

The Technical Specifications require one operable diesel generator in Modes 5 and 6. With the installation of this jumper, EDG 1-2 will remain operable. Energizing the lube oil heater from another source will have no impact on the accidents evaluated in the FSAR Update. In case of an electrical fault associated with the jumper, the supply breakers will clear the fault. The loss of power to the auxiliary panel has no impact on the EDG to start and load. This jumper is installed to maintain lube oil temperature above 90°F and will prevent unnecessary EDG starts to heat up the lube oil. This will permit EDG 1--2 to remain operable and one more EDG will be either operable or available. Based

on the above, this jumper will not reduce the margin of safety as defined in the basis for the Technical Specifications.

4. Control Room Ventilation System Troubleshooting
Jumper 97-007, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-051)

This LBIE associated with Jumper 97-007 assisted with the troubleshooting efforts associated with AR A0427712 that effected the control room ventilation system (CRVS) and the pressurizer acoustic monitors. In order to successfully troubleshoot and repair the circuit, a jumper was needed to lift certain circuits while maintaining the operability of the CRVS.

Safety Evaluation Summary

The evaluation screen for this condition screened "Yes" as a change to the system operation as described in the FSAR Update. The safety evaluation determined that an unreviewed safety question is not involved based on the Technical Specifications (TS) allowing the plant to operate with only one train of CRVS. Since the jumper would only effect one train, the other train would always be available to satisfy the operability requirements. The plant would enter the TS limiting condition for operation for one train inoperable during the evolution.

5. Add Local Manual Control of CND -2-TCV-23
Jumper 97-018 (Units 1 & 2) (LBIE Log No. 97-120)

A temporary local manual control setup was installed to bypass the normal automatic controls of Valve CND-2-TCV-23. This enabled TCV-23 to remain in service during the replacement of a faulty control element while the plant was on line. TCV-23 cannot be removed from service while the plant is operating.

Safety Evaluation Summary

TCV-23 is Class II (nonsafety-related) and is not included in any Technical Specifications. This jumper disabled TCV-23 to respond to a load transient bypass signal (LTBS) as described in the FSAR Update. Plant generation was reduced to below the 69 percent power level during the installation of the jumper and replacement of the control element. The LTBS cannot be initiated below this power level.

6. STSR-97-137 Lead Shielding Request per Procedure RP1.ID2
STSR 97-137, Rev. 0 (Unit 1) (LBIE Log No. 97-060)

This temporary modification allowed installation and removal of temporary lead shielding in Unit 1 containment for Line 256, Rupture Restraints 4-1RR and 4-2RR. The shielding will be installed in Modes 5 and 6 only and removed prior

to entering Mode 4. The shielding will be installed on operable piping which creates a condition that might affect safe operation of the plant not evaluated in the FSAR Update.

Safety Evaluation Summary

The only Mode 5 and 6 accident analyzed in the FSAR Update is a fuel handling accident. The addition of lead shielding onto an operating residual heat removal line does not affect this accident. The blankets' tie-down arrangement is considered structurally adequate such that it will not fail during a seismic event and damage any seismically induced systems interaction targets in the vicinity. Additional weight of the blankets has been evaluated for its impact on the seismic qualifications of piping and found to be acceptable. Based on the above criteria and justification, an unreviewed safety question is not involved.

7. Temporary Modification to the VLPM
Jumper 98-001, Rev. 5A (Unit 1) (LBIE Log No. 98-011)

The vibration and loose parts monitor (VLPM) Channel 6 input lead is lifted by this jumper to prevent nuisance alarms that have been occurring since the Unit 1 eighth refueling outage. The field lead from Channel 6 into the VLPM has a single BNC connector at the end that is disconnected until the source of the noise on the field lead can be determined during the next outage. The implementation of the configuration change reduces the number of inputs as shown in the design documents, and therefore, the design redundancy of the signal from Steam Generator 1-1 loose part monitoring no longer exists. This design redundancy is stipulated in the FSAR Update (Section 4.4.5.4) and, though this limit is descriptive of the system, any change in that description constitutes a change in the FSAR Update text and/or tables. Thus, Question 1a) of the LBIE screen is answered "Yes." Section 4.4.5.4 of the FSAR Update further describes what occurs when the output of an individual transducer channel exceeds an adjustable setpoint. This description includes operator actions and staff actions that qualifies as a procedure as described in the FSAR Update.

Safety Evaluation Summary

The VLPM provides early detection of potential loose parts in the reactor coolant system (RCS) so remedial action may be taken before damage occurs. With one SG 1-1 VLPM channel disabled, one channel remains. The loose parts monitoring computer software has been adjusted to provide an alarm on the one remaining input. The resulting loose parts alert capability is more conservative in this configuration because both channels must read high to initiate an alarm with two channels available. The probability of an accident or equipment malfunction caused by the lifted input lead will not contribute to an increased accident or

equipment malfunction frequency because SG 1-1 loose parts monitoring capability is maintained more conservatively than described in the FSAR Update.

The VLPM is a Class II monitoring system that is not required to mitigate the consequences of any FSAR Update accident or equipment malfunction. This jumper does not raise the consequences of any evaluated accidents or equipment malfunctions in which loose parts are monitored whether the loose parts contribute to the accident or not.

VLPM operability is controlled by ECG 46.1. VLPM function is maintained. No margins of safety for this system are described in the ECG bases or the FSAR Update.

8. Temporary Jumper for Lube Oil Heater to EDG 2-1
Jumper 98-013, (Unit 2) (LBIE Log No. 98-010)

Since Bus F was out of service for maintenance, the power supply to the emergency diesel generator (EDG) lube oil Heater Panel MPF-28 was cleared. In order to maintain lube oil temperature above 90°F, the lube oil heater had to be energized from adjacent Panel MPG-31 using a jumper.

Safety Evaluation Summary

Energizing the lube oil heater from another power source (in this case, its own train) would not have an impact on the accidents evaluated in the FSAR Update. In case of an electric fault associated with this jumper, the supply breaks would clear the fault. Technical Specifications require one operable EDG in Modes 5 and 6. This was satisfied with EDGs 22 or 23. Based on the above criteria and justification, an unreviewed safety question is not involved. Also, a change to the Technical Specifications is not involved.

9. Temporary Modifications/Plant Jumpers
Jumper 98-06, Rev. 1 (Unit 1) (LBIE Log No. 97-042)

The vibration loose parts monitor (VLPM) channel 6 input lead was lifted to prevent excessive nuisance alarms that had been occurring since the Unit 1 seventh refueling outage. Although the input had been taken off scan per Procedure OP1.DC24, the alarms were still coming in to PK 11-11. The lead will remain lifted until the source of the alarms can be determined during the next outage.

Safety Evaluation Summary

This 10 CFR 50.59 safety evaluation was prepared because steam generator (SG) 1-1 VLPM redundancy, as described in the FSAR Update, was reduced

from 2 to 1. Also, actions described in the FSAR Update that occur when an individual transducer channel exceeds an adjustable setpoint were modified.

The VLPM provides early detection of potential loose parts in the reactor coolant system (RCS) so remedial action may be taken before damage occurs. With one SG 1-1 VLPM channel disabled, one channel remains. The loose parts monitoring computer software has been adjusted to provide an alarm on the one remaining input. The resulting loose parts alert capability is more conservative in this configuration because both channels must read high to initiate an alarm with two channels available. The probability of an accident or equipment malfunction caused by the lifted input lead will not contribute to an increased accident or equipment malfunction frequency because SG 1-1 loose parts monitoring capability is maintained more conservatively than described in the FSAR Update.

The VLPM is a Class II monitoring system that is not required to mitigate the consequences of any FSAR Update accident or equipment malfunction. This jumper does not raise the consequences of any evaluated accidents or equipment malfunctions in which loose parts are monitored, whether the loose parts contribute to the accident or not.

VLPM operability is controlled by Equipment Control Guideline (ECG) 46.1. VLPM function is maintained. No margins of safety for this system are described in the ECG bases or the FSAR Update.

10. Determinate Defective Pressurizer Heaters
MMP M000059, Rev. 1 (Unit 2) (LBIE Log No. 97-028)

Maintenance Modification Package (MMP) M000059 allows defective pressurizer heaters to be disconnected. This allows the remaining heaters fed from the same circuit breaker to be returned to service. The initial pressurizer heater capacity was 1800 kW. This MMP allows failed heaters to be disconnected as long as total capacity of at least 1340 kW with Heater Groups 1 and 4 each having at least 276 kW and Groups 3 and 4 each having at least 345 kW is maintained.

Safety Evaluation Summary

The pressurizer heaters are nonsafety related. The purpose of the pressurizer heaters is to control pressurizer pressure during heatup and power operation and to support natural circulation of the reactor coolant system during the loss of offsite power. 150 kW is required to support natural circulation. Technical Specifications define the minimum pressurizer heater capacity as 150 kW from two groups which can be supplied by vital emergency power. This MMP maintains this 150 kW by limiting the number of heaters that can be disconnected. Therefore, all margins of safety implicit in this Technical Specification requirement are maintained by this MMP.

11. Main Feedwater Overspeed Trip Test
Jumper PEP-04R, Rev. 5A (Units 1 & 2) (LBIE Log No. 98-036)

The overspeed trip test is normally performed using main steam. This revision of the procedure makes it acceptable to use a cross-tie to the auxiliary steam system to warm up and overspeed the turbine. The overspeed trip test is performed with the main feedwater pump uncoupled regardless of the source of the turbine steam supply.

Safety Evaluation Summary

The overspeed trip test is performed with the main feedwater pump uncoupled and out of service. The use of an alternate supply of motive steam does not create a new accident or potential malfunction. The potential failure of the jumper is bounded by a break in the auxiliary steam header.

12. Operation of the Component Cooling Water (CCW) System to Support Replacement of Temperature Control Valve (TCV)-130
TP T0-9705, Rev. 0 (Unit 1) (LBIE Log No. 97-088)

This temporary procedure was prepared to support replacement of CCW temperature control valve TCV-130. Due to a leaking return isolation valve, leak tight isolation of the line was not possible. To replace TCV-130, restriction orifice RO-239 had to be replaced with a blank plate so the bypass line would pass flow. It was necessary to establish a bleed path downstream of RO-239 to relieve pressure on the orifice so that its flange could be disassembled and the blank plate installed. New bypass isolation valves were added using a hot tap procedure that was also used to establish the bleed path.

This procedure provided instructions to establish the bleed path from the CCW system and regulate makeup flow during the activities associated with RO-209.

Safety Evaluation Summary

The vital portions of the CCW system are designed to mitigate the consequences of an accident by removing heat from the primary system and transferring it to the ocean. The probability of FSAR Update Chapter 15 accidents is not affected by CCW system operation. The consequences of FSAR Update Chapter 15 accidents are not increased provided CCW system operation is maintained. The temporary procedure provided for manual makeup to maintain CCW surge tank level in the normal range. The bleed rate was within the makeup capability of the makeup water system. The RCS was depressurized or at very low pressure during the maintenance operation to minimize leakage of radioactive contamination. Operation of the CCW system was not significantly affected by this procedure; consequences of analyzed accidents and equipment malfunctions were not increased. No new accidents or equipment malfunctions were created. Adequate inventory was maintained in the CCW surge tank. Technical Specification 3.7.3.1 and its bases were not challenged by this procedure.

13. Installing Turbine Building Siding Near High-Voltage Lines and Equipment
TP TA-9701, Rev. 0 (Unit 1) (LBIE Log No. 97-034)

This temporary procedure was written to guide and control re-siding installation activities during the Unit 1 eighth refueling outage. Re-siding the northeast corner of the turbine building involves work near energized high-voltage sources. The Unit 2- 230-kV and 500-kV lines were energized during work near the 500-kV lines. The work was performed with a combination of suspended scaffolding and manlifts. The 230-kV and 500-kV lines are close together; additional controls were needed to ensure personnel and equipment safety.

Safety Evaluation Summary

This evaluation was performed to evaluate the implementing methods and equipment used for the re-siding work and to verify that failure of the methods and equipment would not affect safety-related equipment and safe plant operation.

Suspended scaffolding was evaluated for lifts over restricted areas, seismic interaction issues, personnel safety and operational loads to ensure structural integrity during installation and operation. Deployment and operation of the 175-ton boom crane and mobile manlifts were in compliance with all applicable procedures. Crane ground path, swing path, and station points were evaluated and documented. Cranes and manlifts were evaluated for tipping issues. Electrical observers were stationed during the work. Crane operators were trained and qualified per ANSI/SIA 92.5. Accident possibility and probability were not increased.

Installation and operation of the equipment as described above will not affect safety-related equipment. Heavy loads were not lifted over exclusion areas. Equipment malfunction possibility, probability, and consequences were not increased.

14. Providing Vital 125 Vdc Power from SD 12 to SD 13 Vital Loads
TP TA-9702, Rev. 0 (Unit 1) (LBIE Log No. 97-035)

This temporary procedure provided instruction to install a Class 1E jumper from dc Bus 12 to power 4-kV Bus H and its associated safeguards relay board in Modes 5 or 6. Normally, dc Bus 13 powers up these loads. However, dc Bus 13 was unavailable because its battery was being replaced. The reconfiguration of vital dc control power enabled dc power from dc Bus 12 to power diesel generator (DG) 12 and associated 4-kV Bus G, and DG 11 and associated 4-kV Bus H.

Safety Evaluation Summary

This temporary configuration was implemented for Modes 5, 6, or while defueled in the Unit 1 eighth refueling outage. Class 1E jumpers from dc Bus 12 to the 4-kV Bus H and it associated safeguards relay board were provided. DG 11 did not require jumpers as it is provided with a dc power transfer switch, which was selected to dc Bus 12. All applicable Technical Specifications and Outage Safety Plan requirements were met. The basis for allowing this temporary configuration was based on the following:

- Battery 12 was shown to have capacity to simultaneously operate both 4-kV buses (G and H) and start both DGs (12 and 11).

- The jumper met class IE requirements and did not introduce new failure modes.

- While operating in Modes 5, 6 or defueled, it is not necessary to postulate a single failure of the cross-train Class IE equipment.

15. Replacement of Auxiliary Transformer 2-1
TP TB-9721, Rev. 1 (Unit 2) (LBIE Log No. 98-020)

This temporary procedure addresses the replacement of auxiliary transformer 2-1 (UAT21). The replacement of UAT21 requires use of a crane and trailer. The process could make startup transformer (SUT) 22 and its deluge system a seismically induced systems interaction (SISI) target. During the Unit 2 eighth refueling outage, the SUT 22 provides offsite power to the vital 4-kV and 480-V ac loads.

Safety Evaluation Summary

In Modes 5 and 6, Technical Specifications require one offsite power source and one emergency diesel generator (EDG) be operable. In the event of failure of SUT 22, the EDG will provide power to the vital loads. During load lifting, the crane and its boom will not be oriented in line with SISI targets and located at a distance that minimizes potential for damage to SUT 22.

There is no inservice equipment important to safety in the area where this activity is performed. Vital 4-kV switchgear is inside the turbine building and damage to the nonvital SUT 22 will not affect the vital Bus E or DG safety function. The safety margin is not affected by this activity since the plant will be in Mode 5 or 6 and the outage safety plan addresses the requirements for power availability.

16. Moving Unit 2 Auxiliary 21 Transformer
TP TB-9721, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-017)

This temporary procedure was used to cover the drayage procedure used by Bragg Crane & Rigging Co. to move the old Auxiliary 21 Transformer out of the protected area and the new UST Auxiliary 21 Transformer from Lot 1 into the protected area.

Safety Evaluation Summary

Replacement of the Auxiliary 21 Transformer required the use of a skid system, a 200-ton crane and a transportation trailer. The work was done during Modes 5 and 6 in the Unit 2 eighth refueling outage and in the vicinity of Startup Transformer 22. The transformers were moved fully dressed and filled with oil. This temporary procedure addressed precautions taken to keep the Startup Transformer and its deluge system operational and also addressed the environmental concerns associated with an oil spill or a fire, and the impact on the Emergency Plan.

17. Implementation of DCP E-49297 Battery 13 Replacement
TP TD-9703, Rev. 0 (Unit 1) (LBIE Log No. 97-039)

This temporary procedure provided instruction to install a nonClass 1E jumper from nonvital Battery 17 to provide power to selected dc Bus 13 loads during the Unit 1 eighth refueling outage. Normally vital 125-Vdc Distribution Panel 13 loads are powered from vital Battery 13. However, due to Battery 13 replacement during the Unit 1 eighth refueling outage, selected Class 1E loads were powered via a nonvital jumper from nonvital Battery 17. The jumpers were necessary to keep SD 13 loads operational and support outage related activities.

Safety Evaluation Summary

This temporary configuration was implemented during Modes 5, 6, or while defueled in the Unit 1 eighth refueling outage. NonClass 1E jumpers from Battery 17 to selected dc Bus 13 loads were provided. The basis for allowing this temporary configuration was based on the following:

- Nonvital Battery 17 was determined to have adequate capacity to power up the selected Class 1E jumpered loads. The circuit breakers and jumpers used in the jumper scheme were evaluated and sized and coordinated for the selected loads.

- The nonvital jumper scheme did not introduce new failure modes or create a different type of accident.

- Only those selected loads whose design classification was non-Q were able to be declared operable. The rest of the loads, even though energized by the temporary jumpers, were declared inoperable and no credit was taken to meet Technical Specification limiting condition for operation requirements.

18. Providing Vital 125 Vdc Power from SD 22 to SD 23 Vital Loads
TP TD-9802, Rev. 0 (Unit 2) (LBIE Log No. 97-184)
TP TD-9803, Rev. 0 (Unit 2) (LBIE Log No. 97-190)

This temporary procedure provided instructions for jumpering vital SD 23 loads to SD 22 for the Battery 23 replacement during the Unit 2 eighth refueling outage.

Safety Evaluation Summary

During the vital Battery 23 replacement in the Unit 2 eighth refueling outage, selected Class 1E loads that were vital to Mode 5 or 6 safety were fed from vital Battery 22. This configuration was reviewed with the Outage Safety Plan and found to not increase the probabilities or consequences of any Mode 5 or 6 accidents previously evaluated in the FSAR Update. No unreviewed safety questions were identified.

19. Energize Unit 1 12-kV Startup Bus from Auxiliary Transformer 11
TP TO-9701, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-055)

This temporary procedure (TP) energizes the Unit 1 12-kV startup bus from Auxiliary Transformer 1-1 and clears Startup Transformer 1-1 for replacement and Startup Transformer 1-2 for maintenance. Loss of offsite power to the operable 4-kV vital buses is the only impact possible from this alignment.

Safety Evaluation Summary

Temporary Procedure (TP) TO-9701 is to be performed in Modes 5 and 6. In these modes, analyzed accidents that may be affected are fuel handling accidents, tank ruptures, and the boron dilution event. Loss of offsite power does not cause or affect mitigation of fuel handling accidents since containment isolation does not require offsite power, nor does the fuel handling building (FHB) ventilation system. Loss of offsite power has no effect on tank ruptures. Loss of offsite power does not affect the ability to secure the primary water makeup pumps - the limiting boron dilution event. A loss of offsite power is mitigated by the emergency diesels starting and assuming the vital bus loads. This temporary procedure has no effect on the ability of the Technical Specification and Outage Safety Plan required emergency power sources. Thus, there is no potential unreviewed safety question.

C. Procedure Changes

1. Core Operating Limits Report (COLR) for DCPP Unit 2, Cycle 9
COLR 2-9, Rev. 0 (Unit 2) (LBIE Log No. 98-026)

This report was performed for the initial issue of COLR 2-9. The COLR for Unit 2 Cycle 9 is the same as for Unit 2 Cycle 8 with the exception of W(z) factors that are cycle specific. Because the safety evaluation was performed by a vendor that is not Plant Staff Review Committee (PSRC)-approved, the answer to Question no.4 for the 50.59 screen on the LBIE Screen was "yes."

Safety Evaluation Summary

The safety evaluation performed for this report is the same as the one performed for the Design Change Package (DCP) N-050368, Rev. 0. That evaluation found that there are no adverse consequences to components or systems due to this core reload design. No new performance changes or demands on other components or systems are introduced by this core design.

2. Using Five-Year Average X/Qs in OffSite Dose Calculations
CAP A08, Rev. 20 (Units 1 & 2) (LBIE Log No. 96-044)

FSAR Update Section 11.3.7 assumed historical annual average X/Q values for calculating dose from normal operations for the licensing basis. Procedure CAP A-8 uses historical five-year average X/Q values for calculating dose under the same conditions.

Safety Evaluation Summary

10 CFR 50, Appendix I, states design objectives and limiting conditions for operation of for nuclear power reactor effluents. Limits to meet these conditions are implemented by Technical Specification 6.8.4.6.

FSAR Update Section 11.3 states the results of a pre-operational analysis for the estimated gaseous effluents and dose during normal operation. The analysis was performed to demonstrate that the criteria of 10 CFR 50, Appendix I, can be met. This analysis assumed annual average X/Q conditions. PG&E believes the calculated dose is the licensing basis.

Procedure CAP A-8, "Offsite Dose Calculations," implements the methodology used during normal plant operations to ensure compliance with 10 CFR 50, Appendix I, and the Technical Specification requirements. CAP A-8 uses five-year historical average X/Q values to calculate radioactive gaseous effluent dose and these values are used as one of the variables to calculate radioactive effluent and radioactive process monitor high alarm setpoints (HASP). The HASP values are used to ensure the dose rate limits are not exceeded. The

dose rate limits are a fixed value. Therefore, as X/Q values increase, the release rate decreases to maintain the dose rate limit. As X/Q decreases, the release rate limit may increase up to the dose rate limit. Thus, HASP's determined by CAP A-8 account for X/Q variations and ensure dose rate limits are not exceeded.

Five-year historical average X/Q values are more representative of average DCPP meteorology conditions than historical average X/Q values (used in the FSAR Update Section 11.3 analysis). The five-year historical average X/Q values may, in any given year, be more or less than the corresponding annual average values as stated as "estimates" in the FSAR Update analysis.

In the current revision 20 of Procedure CAP A-8, the historical five-year X/Q values are less than those in the FSAR Update Section 11.3 analysis. The values used in the analysis are listed in Table 11.3-11, " Estimates of Relative Concentration X/Q at Locations Specified in Table 11.3.-10."

An FSAR Update change to include the use of five-year historical meterological data to calculate X/Q values has been submitted.

3. Offsite Dose Calculations
CAP A-8, (Units 1 & 2) (LBIE Log No. 97-083)

The Offsite Dose Calculation Process (ODCP) X/Q and D/Q values are updated yearly based upon the latest five-year meteorological data. The FSAR Update also lists X/Q and D/Q values. The issue is how does the ODCP X/Q and D/Q revisions impact the FSAR Update values.

Safety Evaluation Summary

10 CFR 50.34a requires nuclear power plants to be designed in such a way that doses due to routine effluent releases not exceed the 10 CFR 50, Appendix I, dose design objectives. The X/Q and D/Q values listed in the FSAR Update, Section 11.3, are used for pre-operational demonstration of compliance with the 10 CFR 50.34a design criteria and, therefore, represent design bases for licensing. For purposes of demonstrating the design criteria, dose pathways and locations are assessed that are not utilized for routine effluent control. The actual dose pathways and locations used for routine effluent controls are based on the annual land use census information, as well as concurrent (latest five-year annual average) meteorological data.

Thus, the FSAR Update X/Q and D/Q values, which are used for 10 CFR 50.34a calculations, are unrelated to the X/Q and D/Q values used for routine effluent dose assessment.

4. Pilot Process Instruction Development
AD1.ID8, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-033)

This is a new procedure that provides requirements and supplemental guidance for developing instructions to control pilot processes. This procedure is in support of the Work Control Process reengineering effort.

Safety Evaluation Summary

This procedure controls how administrative instructions are written and does not directly control activities in the plant, nor does it directly control operation of equipment important to safety. This procedure does not interact with any specified margin of safety as defined in any Technical Specification.

5. Control of the Surveillance Testing Program
AD13.DC1, Rev. 4 (Units 1 & 2) (LBIE Log No. 97-207)

This revision of Procedure AD13.DC1 adds the manual vents and drains between the inner and outer containment isolation valves. The NRC recently rovided additional clarification as to the applicability of Technical Specification (TS) 4.6.1.1a in relation to which penetrations were considered “in service” during accident conditions. License Amendment 73 and 72 relocated TS Table 3.6-1, “Containment Isolation Valves,” to the Diablo Canyon Power Plant Procedures that are subject to the change control provisions in the administrative controls section of the TS. Any change to the containment isolation valve list would constitute a change to the facility and thus would be subject to the provisions of 10 CFR 50.59.

Safety Evaluation Summary

The change is administrative in nature. The change should improve administrative practices without any effect on plant operations. Improved administrative practices increase the likelihood the valves will be maintained closed, thereby improving mitigation potential.

6. Control of the Surveillance Testing Program
AD13.DC1, Rev. 5 (Units 1 & 2) (LBIE Log No. 98-032)

License Amendment Request (LAR) 91-08 proposed relocation of Technical Specification (TS) Table 3.6-1, “Containment Isolation Valves,” to the DCPP procedures that are subject to the change control provisions in the administrative controls section of the TS. This revision of AD13.DC1 adds VAC-2-540 to Attachment 7.7, “Containment Isolation Valves.” This change does not affect the FSAR Update.

Safety Evaluation Summary

This change is administrative in nature and should result in improved administrative practices without any effect on plant operations. The change does not result in any physical modifications and does not alter the method by which any safety-related system performs its function.

Adding VAC-2-540 to the list increases assurance containment integrity is maintained. Improved administrative practices increase the likelihood the valves will be maintained closed, thereby improving mitigation potential.

7. Outage Safety Management of Increased Risk Periods Including Hot Mid-Loop Operations
AD8.DC52, Rev. 4 (Units 1 & 2) (LBIE Log No. 98-018)

This evaluation addressed programmatic issues to incorporate hot mid-loop operations into outage nuclear safety management strategies. Specifically, it addressed a change to a policy statement regarding avoidance of mid-loop operations with fuel in the reactor vessel, and a change in the configuration of the reactor coolant system (RCS) prior to entering reduced inventory operations.

Safety Evaluation Summary

There are no FSAR Update accidents postulated for shutdown events other than a misplaced fuel assembly or fuel handling accident for which this change has no effect.

Changing the authorization process for mid-loop operation, and keeping the reactor head tensioned prior to reduced inventory conditions do not adversely affect RCS or support system hydraulics, heat transfer, pump operation, safety analyses or Technical Specification bases.

The final approval for mid-loop operation still remains with the Vice President and Plant Manager, DCPP. The Vice President and Plant Manager, DCPP is responsible for, and has control over, unit safe operation per the Technical Specifications, FSAR Update Chapter 13, and implementing Program Directives.

Allowing the reactor head to remain tensioned prior to reduced inventory operation does not affect any RCS system in use during shutdown conditions. None of the functions of the residual heat removal system or other systems required for shutdown operations are affected by having a tensioned reactor vessel head prior to reduced inventory conditions.

8. Core Offload Sequence
OP B-8DS1, (Unit 2) (LBIE Log No. 98-019)

Action Request (AR) A0454011 describes an event that occurred during core offload for the Unit 2 eighth refueling outage, stemming from an indeterminate crane failure. Due to the inability to specifically identify the failed component or condition, it was decided to develop an action plan and cautiously proceed.

Safety Evaluation Summary

The crane functions of overload/underload/slack cable still function and are not questioned. The hoist features are separate from the crane lateral movement and overload setpoint features. The gripper and motor failure features are fail-safe and function normally. The event described has no impact on the safety features inherent in the crane design. The safety features, as described in the FSAR Update and Technical Specifications, remain operable, and the inherent safety provided by them is maintained. The Technical Specification requirements remain satisfied in this event and action plan. There is no reduction in margin of safety.

9. OP C-7C:VI, "Transferring/Offloading Sulfuric Acid and Ammonium Hydroxide"
OP C-7C:VI, Rev. 10 (Unit 1) (LBIE Log No. 97-140)
OP C-7C:VI, Rev. 9 (Unit 2) (LBIE Log No. 97-141)

This procedure change added measures to mitigate a chemical spill when offloading chemicals.

Safety Evaluation Summary

The proposed change blocks potential drainage paths when offloading sulfuric acid or ammonium hydroxide. This warranted an environmental protection plan review under the Licensing Basis Impact Evaluation (LBIE) screening criteria. Since the proposed changes would not add any new discharges, would not require a change to the Environmental Protection Plan, would not change quantities of chemicals used or stored at DCPP, nor add any new hazardous waste streams, no unreviewed environmental question exists.

10. EQ Program Implementation in NTS
DLAP CF3.NE8, Rev. 0A (Units 1 & 2) (LBIE Log No. 97-181)

Section 3.11.1.4 of the FSAR Update, "Class 1E Electrical Equipment Qualification List Maintenance," specified that a hard-copy output (a RAMIS Report) of the DCPP EQ Master List information from PIMS constitutes the DCPP Class 1E Electrical Equipment Qualification List and was maintained as a controlled drawing (PG&E Drawing 050909). This Licensing Basis Impact Evaluation (LBIE) was performed to remove the administrative requirement to issued a hard copy of the EQ Master List from the FSAR Update.

The EQ Master List is now a living list that is comprised of certain fields in the PIMS component database. Therefore, there is no value in unnecessarily issuing Drawing 050909.

Safety Evaluation Summary

This administrative change does not affect the operation of the plant or accident initiation, consequences, or probability. It is an FSAR Update revision to change how the EQ Master List is handled. It was previously issued as a hard-copy drawing on a 6-month frequency. Now it is a living document (in the PIMS component database) that is revised on an ongoing basis. The end result is the Master List is always kept current versus being up to 6 months out of date. All changes to the EQ Master List are reviewed on a 6-month frequency, thereby ensuring the accuracy of the living EQ Master List.

11. Design Change Requests and Design Change Vehicles
CF4.ID1, Rev. 3 (Units 1 & 2) (LBIE Log No. 97-208)

This procedure describes the process for initiating design change requests and selecting an appropriate design change vehicle. The procedure revision introduces a new process for Class N Modifications.

Safety Evaluation Summary

This procedure revision involves Class N Modifications that are defined as being minor in nature, do not change a setpoint, do not affect the DCPP design basis, and are not considered to be design changes. Therefore, there can be no reduction in the margin of safety as defined in the basis for any Technical Specification.

12. Reactor Trip or Safety Injection
EOP E-0, Rev. 19 (Unit 1) (LBIE Log No. 97-025)

Emergency Operating Procedure (EOP) E-0 was modified to add an instruction to place two component cooling water (CCW) heat exchangers in service if the reactor coolant system (RCS) is not intact at step 21 as preparation to transfer to EOP E-1.3. An item was also added to the foldout page to transition to EOP E-1.3 if the refueling water storage tank (RWST) level is less than 33 percent.

The changes were made to reduce the operator response time to EOP E-1.3 when aligning the RCS for cold leg recirculation. The specific location of the instruction was chosen to ensure that it would be performed (i.e., not bypassed due to RNO on other steps), and to minimize potential disruptions in the flow of diagnosing and responding to the accident in progress.

Safety Evaluation Summary

The change affects equipment alignment following a loss-of-coolant accident (LOCA), which is not the cause or initiating event of an accident. There is no change to method of operation for any accident mitigation equipment. The possibility and probability of accidents or equipment malfunctions are not affected. Placing two CCW heat exchangers in service at the subject step improves operator response time to a LOCA and does not affect operator response times to non-LOCA accidents diagnosed by EOP E-0. Accident analysis assumptions are not affected if both CCW heat exchangers are placed in service and transfer to cold leg recirculation is not needed. All safety-related equipment verifications will have been performed before transfer to EOP E-1.3 when the RWST level falls to 33 percent. The consequences of an accident are not affected. The transfer does not affect Technical Specification provisions for ECCS operability and long-term core cooling. Safety margins are not affected.

13. Reactor Trip or Safety Injection
EOP E-0, Rev. 20 (Unit 1) (LBIE Log No. 97-011)
EOP E-0, Rev. 11 (Unit 2) (LBIE Log No. 97-012)

Emergency Operating Procedure (EOP) E-0 was revised such that ECA-0.0 will not be performed if any vital bus is energized. The intent is to cope with loss of ac emergency power until at least one emergency bus can be energized.

Prior to this change, one complete train of emergency core cooling system (ECCS) equipment was required to exit emergency contingency guidelines and return to the recovery and functional restoration (E-series and FR-series) guidelines. The operator was directed to remain in ECA-0.0 with one vital 4-kV bus energized because two buses were required to guarantee restoration of minimum safeguards equipment. However, with power restored to one vital bus, some degree of core cooling becomes available. Westinghouse Direct Work No. 92-033 clearly stated that minimum safeguards capacity is not required to be in the recovery and function restoration guidelines.

This change will allow the operators to fully use the emergency procedure network to mitigate concurrent accidents.

Safety Evaluation Summary

The safety evaluation was performed to evaluate the effect on ECCS equipment and to verify that a failure mode could not be created by implementing the E-series or FR-series emergency procedures with less than one full train of safeguards equipment.

The emergency contingency, recovery, and functional restoration procedures are used to mitigate the consequences of accidents. Their use cannot cause an accident.

All FSAR Update accidents were evaluated and validated for recovery with only one 4-kV bus available. In each case, it was determined that recovery was possible. The revised procedure allowed recovery options that were previously not available. Recovery was not impaired and consequences were not increased.

The change provides improved guidance for the operators when a vital bus is energized. Other procedures are adequate for accident mitigation. Use of the modified procedures does not increase the possibility, probability, or consequences of any equipment malfunction or accident. The margin of safety is not reduced because remaining equipment can be operated optimally to maintain core cooling.

14. Reactor Trip or Safety Injection
EOP E-0, Rev. 10 (Unit 2) (LBIE Log No. 97-026)

Emergency Operating Procedure (EOP) E-0, “Reactor Trip or Safety Injection” was revised to include an action to place two component cooling water (CCW) heat exchangers in service if it is determined that the reactor cooling system (RCS) is not intact and a transition to EOP E-1, “Loss of Reactor or Secondary Coolant,” is required. Placing both CCW heat exchangers in service is done in anticipation of an eventual transition to EOP E-1.3. Placing this action in EOP E-0 is advantageous as it removes the operation from the timeline of cold leg recirculation alignment. Also, the foldout page was revised to instruct the operators to go to EOP E-1.3 immediately if the refueling water storage tank (RWST) level is less than 33 percent.

Safety Evaluation Summary

EOP E-0 provides diagnostic steps to provide the operators with the symptoms and appropriate actions for main steam line break (MSLB), steam generator tube rupture (SGTR), and loss-of-coolant accident (LOCA). It also provides a direct path to terminate a safety injection (SI). The accident analyses for MSLB and SGTR, and the analysis for inadvertent SI assume specific operator response times.

The addition of a step to place both CCW heat exchangers in service following a LOCA does not impact these analyses. Accident mitigation for the LOCA is not adversely affected as the timeline for realignment for cold leg recirculation is improved. If a LOCA is diagnosed and transfer to cold leg recirculation is not needed, alignment of the second heat exchanger does not significantly delay the actions of EOP E-1; therefore, accident analysis assumptions are not altered.

15. Loss of Reactor or Secondary Coolant
EOP E-1, Rev. 14 (Unit 1) (LBIE Log No. 97-022)
EOP E-1, Rev. 8 (Unit 2) (LBIE Log No. 97-023)

This emergency operating procedure revision deletes the step that verifies that the water level in the containment recirculation sump is sufficient to support the operation of the residual heat removal (RHR) pumps in cold leg recirculation. The adequacy of the recirculation sump level to support RHR pump operation is now verified in EOP E-1.3 prior to placing the RHR pumps into service. Delaying the verification until this time allows for more inventory to collect in the sump. This reduces the potential for unnecessarily entering ECA-1.1.

Safety Evaluation Summary

The purpose of checking the level in the containment recirculation sump is to confirm that there is sufficient water available to support the operation of the RHR pumps during cold leg recirculation. Deleting this step from E-1 does not create an unreviewed safety question as this step is now performed in EOP E-1.3 just prior to placing the RHR pumps in service. Delaying this verification step to EOP E-1.3 decreases the potential of inadvertently entering ECA-1.1 due to insufficient sump level. Entering ECA-1.1 unnecessarily would delay the operator's overall response to the event. EOP E-1.3 contains guidance to enter this procedure if sump level is not adequate when the step is reached to place the RHR pumps in service. Additionally, operators are instructed to monitor for RHR pump cavitation.

16. EOP E-1.3, “Transfer to Cold Leg Recirculation”
EOP E-1.3, Rev. 6 (Unit 1) (LBIE Log No. 96-025)
EOP E-1.3, Rev. 5 (Unit 2) (LBIE Log No. 96-026)
EOP E-1.3, Rev. 6 (Unit 2) (LBIE Log No. 97-002)
EOP E-1.3, Rev. 7 (Unit 2) (LBIE Log No. 97-021)

This procedure describes the process of reconfiguring emergency core cooling pumps and valves from the injection phase of a loss-of-coolant accident (LOCA) to the recirculation phase of such an event. This process is described in detail in the FSAR Update, so any changes to that sequence require an evaluation under 10 CFR 50.59. The proposed revisions added a few check and action steps to the process. It should also be noted that this evaluation covered all previous revisions to the procedure, which modified this sequence in various ways, but were not evaluated under 50.59.

Safety Evaluation Summary

The FSAR Update includes a statement that the above described process is completed in “approximately 10 minutes.” As demonstrated analytically and through simulator runs, this sequence could be accomplished in such a time, and the addition/deletion of some of the FSAR Update-described steps does not conflict with that statement. Furthermore, the steps being added/deleted were necessary to assure proper completion of the switchover, and do not result in depletion of the refueling water storage tank (RWST) (which would require termination of injection during a LOCA) before recirculation has begun. Therefore, the modification of the FSAR Update-described sequence does not challenge the operator’s ability to successfully transfer to cold-leg recirculation within the required timeframe in order to mitigate a LOCA. An unreviewed safety question is not involved.

17. Transfer to Cold Leg Recirculation
EOP E-1.3, Rev. 15 (Unit 1) (LBIE Log No. 97-020)
EOP E-1.3, Rev. 7 (Unit 2) (LBIE Log No. 97-021)

This emergency operating procedure revision moves the requirement to check the containment recirculation sump level check to just prior to starting the residual heat removal (RHR) pumps, and to move the requirement to locally close the breakers for the refueling water storage tank (RWST) suction isolation valves to the start of the procedure. Other changes increase the usability and efficiency of the procedure. As a result, the time to switchover is reduced by 45 seconds.

Safety Evaluation Summary

Restructuring the emergency operating procedure (EOP) steps reduces the time required to reach cold leg recirculation. Delaying the verification of the

recirculation sump level reduces the possibility of inadvertently entering ECA-1.1 in response to inadequate sump level. Guidance has been added to ensure that RHR pump cavitation due to inadequate suction is identified, and the procedure continues to direct the operators to take the appropriate action in response to this condition. Improving the timeliness of the switchover to cold leg recirculation ensures that the design basis for the emergency core cooling system is maintained during realignment.

18. Transfer to Cold Leg Recirculation
EOP E-1.3, Rev. 14 (Unit 1) (LBIE Log No. 97-001)
EOP E-1.3, Rev. 6 (Unit 2) (LBIE Log No. 97-002)

This revision added steps to accentuate the need for timeliness and to allow certain steps to be performed in parallel. The evaluation also covered all past revisions to Emergency Operating Procedure (EOP) E-1.3 since safety evaluations were not performed for some revisions or were considered to be inadequate for others.

Safety Evaluation Summary

FSAR Update Tables 6.3-4 and 6.3-5 and Sections 6.3.1.4.4.2, 6.3.1.4.4.3, and 6.3.2.17 describe the process of transfer from the emergency core cooling system (ECCS) injection mode to the cold leg recirculation mode of operation after a loss-of-coolant accident (LOCA). Table 6.3-5 contains the basic sequence of operations to establish cold leg recirculation. Certain steps of EOP E-1.3 have been modified such that the sequence of operations is somewhat different than that described in the FSAR Update.

The following steps have been added to EOP E-1.3 that do not appear in FSAR Update Table 6.3-5:

- Step 3.d, which verifies the ASW/CCW is aligned for two ASW pumps through two heat exchangers

- Steps 5.d.3) and 7.f.3), which verify decreasing the RHR heat exchanger outlet temperatures after their respective RHR pumps have been started

- Step 6.a, which closes the CCP recirculation valves 8105 and 8106

- Steps 6.d. and 6.g.2), which throttles the RHR heat exchanger outlet valves when the RHR pumps begin supplying suction flow to the SI and CCPs

Additionally FSAR Update Table 6.3-5 identifies Valves 8701 and 8702 as being checked closed in order to provide RCS to RHR suction isolation. This is not explicitly done in EOP E-1.3, since these valves are maintained closed in Modes 1-3.

FSAR Update Section 6.3.1.4.4.2 states that the total time for the changeover from injection to recirculation is approximately 10 minutes, as shown in Table 6.3-5. The purpose of FSAR Update Table 6.3-5 is to provide a guideline for the emergency operating procedures to accomplish the transfer to cold leg recirculation in approximately 10 minutes. The importance of the 10 minutes is to ensure that there is adequate water inventory in the refueling water storage tank (RWST) for the continuous cooling to the core/containment by the centrifugal charging pumps (CCPs), safety injection pumps (SIPs), and containment spray pumps (CSPs). The transfer to cold leg recirculation must be completed prior to running out of inventory in the RWST.

Emergency Procedure (EP) EOP-1.3, Rev. 0, contained a step that checked the position of several MOVs and a step to locally close breakers for Valves MOV 8980 and MOV 8976. It is assumed that an operator would be dispatched to close these breakers at that step, and at the point closing the valves is requested, it would have been accomplished. There is adequate time in the procedure as detailed in FSAR Update Table 6.3-4A for this to occur. It should

be noted that in the current revision of EOP E-1.3, this action is moved to step 9.b.2, which is after the transfer to cold leg recirculation is completed. Neither of these two items would have an appreciable impact on the ability to complete the transfer in approximately 10 minutes. This review is considered to bound all the past revisions of EOP E-1.3 up to and including Revision 14.

The stated transfer time to cold leg recirculation of 10 minutes is an informational guideline as stated in the FSAR Update by the use of the term “approximately 10 minutes.” The 10 minutes is considered a guideline since considerable margin exists in the assumptions in the table for ECCS pump flows and useable volume in the RWST between the low-alarm RHR pump trip level and the low-low alarm level (4 percent). Simulator validation with randomly selected operating crews demonstrated that the transfer to cold leg recirculation could be accomplished in the required timeframe. Results of that simulator testing are documented in AR A0416238.

In Revision 0 of EP E-1.3, dated March 11, 1985, closure of motor-operated Isolation Valves SI-8805A/B, 8976, and 8980 were moved to the nontime-critical part of the procedure, i.e., after both RHR pumps were aligned to the suctions of the CCP and SI pumps. There is no discussion in the procedure history sheets as to why this change was made, although it may have been due to a single failure analysis of an RHR pump after the first RHR pump is aligned to the suction of the SI pumps, and the resulting loss of SI flow if the 8976 valve were closed.

Several NCRs and ARs have discussed check valve testing and design basis in the past: NCRs DC0-91-TN-N026, DC0-93-TP-N028, DC0-93-TS-N042, and DC0-93-NS-N002, ARs A0351369, A0291455, and A0315425.

Operation of the Check Valves SI-8924, 8977, and 8981 in these lines can be credited. The functional description of these valves for the Inservice Testing (IST) program is contained in NPG Calculation N-124. This calculation was prepared in response to NCR DC0-93-TP-N028, to define the IST testing criteria and basis for check valves. N-124 states for each of these valves: "This valve has a safety function for a short period of time in the closed direction to prevent the discharge of potentially highly radioactive post-LOCA containment recirculation sump water to the RWST during the switchover from the injection phase to the cold leg recirculation phase of safety injection."

The post-LOCA recirculation leakage calculated limit into the RWST per Calculation N-169 and N-170 is 11.26 gpm. These calculations were performed to evaluate the consequences of leakage of post-LOCA recirculation fluid to the RWST. Whole body and thyroid doses to the control room, exclusion area boundary, and low population zone were calculated. It was concluded that the contribution to the dose from recirculation loop leakage to the RWST is negligible for any leakage that is likely to result from check valve leakage.

As a result of the above discussions, it was acceptable to move the closure of the RWST motor-operated valves to the nontime-critical part of EOP E-1.3. It is further acceptable that certain actions be performed outside the control room due to concerns raised relative to spurious actuation. Neither the consequences nor the likelihood of an accident are increased by these changes.

19. Transfer to Hot Leg Recirculation
EOP E-1.4, Rev. 11 (Unit 1) (LBIE Log No. 97-005)

This procedure revision removes the requirement for auxiliary saltwater (ASW) train separation. A requirement was added to contact the Technical Support Center (TSC) for an evaluation of train separation and component cooling water (CCW) train separation, contingent upon TSC direction to do so.

Safety Evaluation Summary

This procedure revision provides greater flexibility in responding to an active failure while allowing train separation to mitigate a passive failure after the first 24 hours. All affected items are used to mitigate an accident and are not considered as initiators of any accident. Therefore, there are no adverse consequences of this revision.

20. Transfer to Hot Leg Recirculation
EOP E-1.4, Rev. 4 (Unit 2) (LBIE Log No. 97-006)

Emergency Operating Procedure (EOP) 1.4 was revised so that component cooling water (CCW) and auxiliary saltwater (ASW) train separations are not required following transfer to hot leg recirculation. With both systems aligned to separate trains as required by the previous EOP revision, there was a concern that a postulated of loss of Bus F power would cause loss of containment heat removal due to loss of flow in one train and loss of ASW flow to the other CCW train. The procedure change allows realignment of ASW and CCW into separate trains to be performed after transfer to hot leg recirculation as directed by the Technical Support Center.

Safety Evaluation Summary

This 10 CFR 50.59 safety evaluation was performed because the description of ASW and CCW train separation as described in FSAR Update Section 9.2.2, Table 9.2-7, and Section 9.2.7.2 was changed to remove the requirement for train separation following transfer to hot leg recirculation. At the same time, train separation is not prohibited as a long-term recovery action if plant configuration and operating conditions warrant the action.

Separation of the CCW and ASW trains following transfer to hot leg recirculation is a long-term recovery action following an accident, and is not related to the cause of an accident or equipment malfunction. The changes affect accident mitigation by providing greater flexibility in responding to an active failure. Train separation to mitigate a passive failure after the first 24 hours is still allowed. These actions can be taken within the timeframe specified in the FSAR Update. Consequences of an evaluated accident are not increased.

21. Revision to Emergency Operating Procedure for Transfer to Hot Leg Recirculation
EOP E-1.4, Rev. 13 (Units 1 & 2) (LBIE Log No. 97-008)

This operations emergency procedure gives the necessary sequence of steps to maintain long-term core cooling following a loss-of-coolant accident (LOCA). This procedure is implemented during the first day following an accident and it limits precipitation of coolant boron onto cores surfaces that could degrade fuel rod heat transfer.

Safety Evaluation Summary

The revision was made to address the possibility that the loss of a single vital ac power source to safety-related equipment could interrupt emergency core cooling if redundant trains of cooling are physically separated (a method for passive failure protection during the long-term core recovery process). The decision to separate trains now belongs to the site emergency organization (Technical Support Center) and will be based upon the plant conditions that exist at that time. Other alternatives for passive failure protection remain available.

22. Testing and Maintenance of Battery Pack Emergency Lights Inside Power Block
MP E-67.5A, Rev. 15 (Units 1 & 2) (LBIE Log No. 97-030)

Revised maintenance procedure to combine all battery-operated light (BOL) testing into one procedure (was previously contained in Surveillance Test Procedure (STP) M-17C1/C2A/C2B).

Safety Evaluation Summary

Testing of BOLs was previous performed using Surveillance Tests (M-17C1, M-17C2A, M-17C2B) and will now be performed by a Maintenance Procedure (MP E-67.5A). This differs from commitments described in FSAR Update Appendix 9.5B, Section C.5, which states, "Test programs are laid out in detail in surveillance test procedures and are controlled by the QA Manual…." and "Procedures governing periodic inspections are laid out in the surveillance test procedures." Change from STP to MP will require a change to the Fire Protection Plan as described in the FSAR Update. This LBIE supports the use of MP for testing and inspection.

23. Loss of All Vital AC Power
EOP ECA-0.0, Rev. 11 (Unit 1) (LBIE Log No. 97-009)

Emergency Operating Procedure (EOP) ECA-0.0 was written to address the loss of all vital ac power. It has been revised such that it may now be exited when a single vital bus is energized. The previous operating philosophy required that a complete train of emergency core cooling system equipment be restored prior to exiting ECA-0.0. The change in philosophy is supported by the Westinghouse Owner's Group determination that the availability of minimum safeguards capacity is not a requirement for being in other optimal recovery guidelines and function restoration guidelines.

Safety Evaluation Summary

The total loss of vital ac, as well as the loss of two vital buses, is beyond the single failure design basis of DCPP. Modification of EOP ECA-0.0 to allow operators to return to the recovery guidelines (E and FR series procedures) when one vital bus has been restored improves the ability to cope with this beyond design basis accident. The modification of this post-accident response procedure does not increase the probability or possibility of an accident. The purpose of ECA-0.0 is to respond to multiple failures. Exiting the procedure with only one vital bus does not ensure that further malfunctions are prevented; however, the use of the full network of emergency procedures improves the overall response to the postulated plant condition.

24. Loss of All Vital AC Power
EOP ECA-0.0, Rev. 6 (Unit 2) (LBIE Log No. 97-010)

Emergency Contingency Guideline ECA-0.0 was revised such that it will not be performed if any vital bus is energized. The intent is to cope with loss of ac emergency power until at least one emergency bus can be energized.

Prior to this change, one complete train of emergency core cooling system (ECCS) equipment was required to exit emergency contingency guidelines and return to the recovery and functional restoration (E-series and FR-series) guidelines. The operator was directed to remain in ECA-0.0 with one vital 4-kV bus energized because two buses were required to guarantee restoration of minimum safeguards equipment. However, with power restored to one vital bus, some degree of core cooling becomes available. Westinghouse Direct Work No. 92-033 clearly stated that minimum safeguards capacity is not required to be in the recovery and function restoration guidelines.

This change will allow the operators to fully use the emergency procedure network to mitigate concurrent accidents.

Safety Evaluation Summary

The safety evaluation was performed to evaluate the effect on ECCS equipment and to verify that a failure mode could not be created by implementing the E-series or FR-series emergency procedures with less than one full train of safeguards equipment.

The emergency contingency, recovery, and functional restoration procedures are used to mitigate the consequences of accidents. Their use cannot cause an accident.

All FSAR Update accidents were evaluated and validated for recovery with only one 4-kV bus available. In each case, it was determined that recovery was possible. The revised procedure allowed recovery options that were previously not available. Recovery was not impaired and consequences were not increased.

The change provides improved guidance for the operators when a vital bus is energized. Other procedures are adequate for accident mitigation. Use of the modified procedures does not increase the possibility, probability, or consequences of any equipment malfunction or accident. The margin of safety is not reduced because remaining equipment can be operated optimally to maintain core cooling.

Commitments to the NRC regarding maintenance of core cooling with ac power unavailable are maintained.

25. Service Cooling Water - Alternate Cooling Supplies to SCW Heat Exchangers
OP F-1:VI, Rev. 3 (Units 1 & 2) (LBIE Log No. 97-058)

Per the FSAR Update, saltwater is the cooling medium for the service cooling water (SCW) heat exchangers. This procedure revision allows firewater to supply cooling to the SCW heat exchangers as an alternate source during outages when the circulating water system is shut down and the auxiliary header is cleared.

Safety Evaluation Summary

During the time firewater is used to cool the SCW heat exchangers, the unit secondary side is in an outage condition. The SCW system has no effect or impact on the plant safety at this time. The low operating pressure and temperature of the system minimize the probability of line failure.

At the time firewater is used as alternate cooling, there is no safety-related equipment in the area. The firewater hose reel system is a seismically qualified system that can be isolated by sectionalizing within the plant. The physical location of lines and components cooled by the system is such that the failure would not affect any safety-related Design Class 1 equipment or components.

26. Makeup Water Sources to the CCW System
OP F-2:VII, Rev. 1 (Unit 1) (LBIE Log No. 97-131)

Instructions were added to the operating procedure to use the firewater storage tank (FWST) contents to supply the component cooling water (CCW) system if needed. The use of the FWST for CCW makeup is described in FSAR Update Section 9.2.2.3.3. Prior to this revision, such usage was not addressed in an operating procedure.

Safety Evaluation Summary

The procedure change does not affect the status of any plant system prior to an accident. The FWST is used for CCW makeup only after failure of the CCW system and several other makeup sources. The specific alignment is not associated with any FSAR Update accident; it adds an additional backup source of CCW makeup and adds flexibility to the ability of operations to mitigate FSAR Update-analyzed accidents concurrent with certain failures. Accident and equipment malfunction probabilities and consequences are not increased.

27. Makeup Water Sources to the CCW System
OP F-2:VII, Rev. 1 (Unit 2) (LBIE Log No. 97-132)

The procedure was revised to include the specific steps to align the firewater storage tank as a backup source to the CCW system, as described in the FSAR Update. The revision also requires the concurrence of Chemistry and Environmental Operations prior to using the primary water storage tank as a backup source for CCW makeup.

Safety Evaluation Summary

The changes to the procedure ensure that alternate supply sources of makeup water for the CCW system are available. The availability of backup supplies increases the reliability of the CCW system. The alignment of the backup source is already described in the FSAR Update; therefore, this change does not increase the probability or consequences of an accident or malfunction. The consequences of a potential breach of the CCW system are reduced by the flexibility of the multiple backup water sources.

28. Chemistry Control Limits and Action Guidelines for the Secondary Systems
OP F-5:II, Rev. 19 (Unit 1) (LBIE Log No. 98-037)

This procedure revision proposes to use pyrrolidine, as a pH control agent, for chemical injection into the Unit 1 secondary system during operation. Currently the procedure specifies that ethanolamine (ETA) is to be used as the pH control agent. This proposed activity is being done as an Electric Power Research Institute (EPRI) Tailored Collaboration Project to evaluate actual plant performance of an alternate amine (pH control agent) in reducing corrosion product transport. Control of pH in the secondary cycle of pressurized water reactor plants is essential to minimize corrosion of secondary system components.

Safety Evaluation Summary

The use of pyrrolidine in the condensate/feedwater system and in the steam generators will enhance equipment integrity due to reduced corrosion rates at room temperature pH in these systems. It will not adversely affect any other secondary equipment. Since the use of pyrrolidine is expected to increase system pH, the elevated pH will reduce iodine volatility to some point less than presently evaluated, thus making the current FSAR Update evaluation more conservative.

No equipment is being installed or modified in the plant as a result of the use of pyrrolidine for pH control in the secondary system. Secondary water chemistry and/or the use of chemical additives or chemical controls for the secondary cycle is not addressed in the Technical Specifications. There is no reduction in the margin of safety as defined in the bases for any Technical Specification.

29. Chemistry Control Limits and Action Guidelines for the Secondary Systems
OP F-5:II, Rev. 15 (Units 1 & 2) (LBIE Log No. 97-056)

The procedure establishes the chemistry control limits for the condensate/feedwater and steam side of the plant. It identifies guidelines for corrective actions should limits be exceeded. This procedure revision introduces a new chemical to be used for scavenging oxygen from feedwater during system operation and from steam generator water when they are in wet lay-up during cold shutdowns. The new chemical, carbohydrazide (Nalco 1250+), supplements use of hydrazine as discussed in the procedure. Limits for its use and corrective action guidelines were provided.

Safety Evaluation Summary

This procedure revision involves a chemical that is in use at other oressurized water reactor power plants for the same functions as described above. The new chemical, carbohydrazide, was tested and evaluated to assure no material compatibility or chemical reaction issues that could contribute to corrosion that may increase the probability of or consequence of in a steam generator tube rupture, rupture of a main feedwater pipe, rupture of a main steam line or potential missiles from the main turbine.

The use of carbohydrazide, with respect to equipment important to safety, was determined to be bounded by the use of hydrazine, as described in the FSAR Update. There are no Technical Specifications associated with secondary chemistry control.

The use of carbohydrazide is not described in the National Pollutant Discharge Elimination System permit but since it is a less toxic chemical than hydrazine, as determined by testing, and non-hazardous, as identified per 29 CFR 1910.1200, prior approval was obtained from the California Regional Water Quality Control Board.

30. RHR Valves 8701/8702 Interlock Jumper Installation and Removal
MP I-38-M.1, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-046)

A procedure was written to install a jumper(s) for residual heat removal (RHR) when de-energizing the solid-state protection system (SSPS) output cabinet(s). The RHR suction valves interlock relays are powered from the SSPS output cabinets. To maintain the ability to open the RHR suction valve(s) when the SSPS output cabinet(s) are be de-energized, new Procedure MP I-38-M.1 will allow the installation of a jumper(s) to lock-in the RHR suction valve(s) open permissive. This defeats the "block opening" interlock. Jumper installation is limited to Mode 6 and defueled only.

When installing a jumper prior to de-energizing SSPS Train B with the RCS >390 psig or pressurizer vapor space >475ºF, the "block opening" interlock for Valve 8701 is defeated.

When installing jumper prior to de-energizing SSPS Train A with the RCS >390 psig, the "block opening" interlock for Valve 8702 is defeated.

Safety Evaluation Summary

This change only applies to Mode 6 with fuel removed from the reactor vessel. Therefore, because the RCS is depressurized, the change does not involve an unreviewed safety question.

31. OP J-2:I, “Main and Aux Transformer Return to Service”
OP J-2:1, Rev. 5 XPR (Unit 1) (LBIE Log No. 96-033)

This evaluation was written for an operating procedure that reflected the operation of DCPP Unit 1 without Auxiliary Transformer 1-1, which was destroyed during an attempt to energize it with a grounding device installed. The LBIE covered the change in plant configuration, as well as operation of the plant under such conditions. The plant configuration provided startup power to the units’ non-vital buses, allowing operation of the circulating water pumps and reactor coolant pumps continuously on the immediate-access offsite power source.

Safety Evaluation Summary

The evaluation documented that this configuration differed from that described in the FSAR Update, but that the consequences of a complete loss of flow (CLOF) event were not changed. Although the proposed configuration results in a slight increase in frequency of a CLOF event, it does not alter its classification as a Condition III event. An unreviewed safety question is not involved.

32. OP L-4, “Normal Operation at Power”
OP L-4, Rev. 38 (Unit 1) (LBIE Log No. 97-145)
OP L-4, Rev. 25 (Unit 2) (LBIE Log No. 97-146)

This procedure change was made to document a limitation described in FSAR Update Section 15.2.6.1. The limitation is adequately bounded by adding a restriction not to restart a reactor coolant pump while the reactor is critical.

Safety Evaluation Summary

Since the proposed change completely bounds and prevents violation of the FSAR Update-described limitation, the procedure does not involve a change to

the facility design, function, or method of performing the function as described in the FSAR Update. An unreviewed safety question is not involved.

33. Plant Cooldown from Minimum Load to Cold Shutdown
OP L-5, Rev. 41 (Unit 1) (LBIE Log No. 97-041)
OP L-5, Rev. 26 (Unit 2) (LBIE Log No. 97-040)

There was a discrepancy between FSAR Update Section 5.1.6.3 and OP L-5 regarding normal plant cooldown. The FSAR Update stated that steam was dumped to the main condenser. While true, steam is also dumped to the atmosphere via the 10 percent atmospheric dump valves during normal cooldown. An FSAR Update change was submitted to clarify use of the 10 percent steam dump valves.

Safety Evaluation Summary

The 10 percent atmospheric steam dump valves are normally used to control or reduce primary temperatures if the main condenser is not available. Use of the valves during normal cooldown, in the absence of any FSAR Update-analyzed accident or event, will not increase the probability of an accident or the probability of valve failure. Similarly, steam dump valve use during normal cooldown will not increase the consequences of an accident or create the possibility of a new accident or equipment malfunction. Technical Specification (TS) design margins are not affected by atmospheric dump valve use during normal cooldown.

34. Feed and Bleed of the CCW System
PEP M-246, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-182)

This procedure de-concentrates the component cooling water (CCW) system's exhausted chemicals by continuously adding makeup water to the surge line while draining CCW from the heat exchanger through temporary connections.

Safety Evaluation Summary

Even though this procedure places the CCWS in an unanalyzed configuration, the evaluation concludes that, there are adequate, dedicated personnel stationed to isolate the temporary connections and place the CCWS in a normal line-up in the event of abnormal indications. The evaluation indicates that the most likely problem encountered with this test is leakage due to failure of the temporary connections. The CCWS has, however, been analyzed in the FSAR Update for flooding near and leakage from the CCW heat exchangers.

35. Reactor Vessel Stud Tensioning
MP M-7.2, (Units 1 & 2) (LBIE Log No. 98-030)

The proposed change involved revising the reactor vessel stud tensioning and detensioning procedures to include new stud tensioning/detensioning sequences and corresponding tensioner pressures and revising the procedure to include a larger acceptable elongation tolerance range. As part of this optimized procedure, tensioning may be accomplished with the use of either six or three hydraulic tensioners, and may even be completed with only two tensioners in the event of a tensioner failure during the procedure.

Safety Evaluation Summary

The proposed procedure change involved no changes to the material of construction for configuration of the affected system (reactor vessel closure flange). The proposed change to the tensioning procedures has no possible impact on the analyzed fuel handling accidents. While the proposed procedure change does permit the reactor vessel studs to have a larger preload stress than has been previsouly permitted by the procedure, the closure flange and studs are demonstrated to meet acceptable ASME Code stress and fatigue limits, so there is no reduction in the margin of safety of any affected components.

36. Manual Installation of Steam Generator Nozzle Dams
MP M-7.61 (Units 1 & 2) (LBIE Log No. 97-062)

This procedure is for the inspection, installation, removal, and refurbishment of the steam generator primary nozzle dams. Use of the nozzle dams is necessary to permit performance of maintenance activities in the steam generator channel heads with the water level of the reactor coolant system (RCS) above the nozzles, such as during refueling operations. Additionally, the nozzle dams minimize the potential for the loss of foreign objects into the RCS piping from the steam generator channel head.

Safety Evaluation Summary

The design pressure of the nozzle dams exceeds both the normal and anticipated accident conditions. The seismic operating basis earthquake maximum load is less than the tested pressure of the nozzle dams. Precaution and limitation steps described in Operating Procedure A-2:III also help to ensure the design and tested loads are not exceeded. Based on the above, use of the nozzle dams have been evaluated and do not represent an unreviewed safety question, nor do they reduce the margin of safety as defined in the licensing documents.

37. Comparison of Final Feedwater Flow Nozzles to “AMAG”
PEP M-98A, Rev. 4 (Unit 2) (LBIE Log No. 97-178)

A cross-flow ultrasonic flow meter was installed on Unit 2 to replace the failed Controlatron system. The system is mounted externally to the final feedwater

header in the turbine building. Data are collected and then used to establish a correction factor for the operator heat balance, STP R-2B. This revision to the procedure relaxed the frequency of data collection and increased the data precision requirement since the plant process computer is the preferred data source.

Safety Evaluation Summary

The flow meter is used to set reactor power and, therefore, the calibration of the instrument remains safety related. Use of this procedure revision will not increase the uncertainty in reactor power above that required by Regulatory Guide 1.49. The externally mounted system will not breach any pipe should the hardware fail. In addition, reactor power will not change as a result of the system failing as there is a human/machine interface required to analyze the data before use.

38. Plant Demineralizer Media
CAP O-10, Rev. 1 (Units 1 & 2) (LBIE Log No. 98-008)

Use of up to 39 cubic feet of resin in any deborating demineralizer vessel (Units 1 and 2) is evaluated for the purpose of forced oxidation or deboration.

Safety Evaluation Summary

This change allows for an additional 9 cubic feet of resin to be loaded into a deborating demineralizer vessel for a total volume of 39 cubic feet. The additional volume will optimize cleanup and minimize radwaste during forced oxygenation of the reactor coolant system. The FSAR Update and Design Criteria Memorandum (DCM) describe the vessels as having a resin volume of 30 cubic feet. The vessel design drawing allows for a total of 39 cubic feet. The need to revise the FSAR Update and DCM to reflect the use of more than 30 cubic feet on resin in the deborating demineralizer vessels was addressed.

39. Notification of the Chemistry or Radiation Protection Sections
OP O-3, Rev. 19 (Units 1 & 2) (LBIE Log No. 97-130)

This procedure is part of the Chemistry Control Program. This revision adds a requirement that concurrence be obtained from Chemistry prior to using primary water in a nonradioactive system and specifically mentions use of primary water as makeup to the component cooling water (CCW) system. Section 9.2.2.3.3 of the FSAR Update states, “If the primary water makeup to CCWS valve is to be opened, the plant operator must obtain concurrence from the Chemistry and Radiation Protection Group.”

Safety Evaluation Summary

This procedure revision is an administrative change only for the purpose of bringing this procedure into agreement with the FSAR Update. The increase in administrative control does not increase the probability of an accident or the consequences of an accident. Therefore, there is no adverse impact on current plant safety.

40. Control of Flammable and Combustible Materials
OM8.ID4, Rev. 5 (Units 1 & 2) (LBIE Log No. 97-126)

This procedure revision clarifies the controls required for combustible materials when introduced into the plant and the amount that may be introduced without being regarded as "bulk storage."

Safety Evaluation Summary

The guidance provided by this revision ensures the introduction of combustible materials will not impact DCPP's ability to achieve and maintain safe shutdown as described in the FSAR Update. There are no adverse consequences due to this revision.

41. General Authorities and Responsibilities of Operating Personnel
OP1.DC10, Rev. 4 (Units 1 & 2) (LBIE Log No. 97-118)

This procedure change added the Work Control Shift Foreman (SFM) position and related responsibilities to the shift operating personnel. FSAR Update Section 13.1.2.2.2.4 describes the shift operating personnel, including the Unit Shift Foreman. A "Work Control" Shift Foreman position was being implemented to perform some of the administrative functions of the SFM. Since an FSAR Update change was being made to support this change, a safety evaluation was performed.

Safety Evaluation Summary

Since there is no change being proposed for the duties and responsibilities of the Unit Shift Foreman (SFM) (as described in the FSAR Update), and since adding a Work Control SFM will serve to enhance the crew's ability to respond to an emergency, the proposed change will not increase the probability or consequences of an accident previously described in the FSAR Update. An unreviewed safety question is not involved.

42. Revision to Plant Administrative Procedure on the Authorities and Responsibilities of Operating Personnel
DLAP OP1.DC10, Rev. 3 (Units 1 & 2) (LBIE Log No. 96-043)

This Operations Department Administrative Procedure establishes authorities and responsibilities of plant Operators, Shift Supervisors, Shift foremen, and Shift Technical Advisors in terms of procedure usage, response to instrumentation, actions in emergencies, and other related matters.

Safety Evaluation Summary

This procedure was revised to allow the unit Shift Foreman to delegate some administrative duties to permit better control room supervision. FSAR Update Section 13.1.2.2.2.4 describes the Shift Foreman's responsibilities.

43. Control of Plant Equipment Not Required by the Technical Specifications
OP1.DC16, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-102)

In letter DCL-95-222, dated October 4, 1995, PG&E submitted License Amendment Request (LAR) 97-07 that proposed to relocate several Technical Specifications (TSs) to Equipment Control Guidelines (ECGs) and to reference the ECGs in the FSAR Update. During review of LAR 97-05, the NRC staff requested PG&E to add the following wording to FSAR Update Section 16.1: "ECGs containing relocated TSs are incorporated into the FSAR Update, by reference, in Table 16.1-1. For ECGs listed in Table 16.1-1, if the equipment cannot be returned to service as required by the ECG, then a review in accordance with 10 CFR 50.59 is required."

PG&E made these changes to the FSAR Update, and incorporated them into plant procedures by revising OP1.DC16, Section 5.5, "Noncompliance with Equipment Control Guidelines," to add:

Attachment 7.2, "Equipment Control Guidelines - Technical Specifications Relocated in Accordance With NRC's Final Policy Statement on Technical Specification Improvements." The ECGs listed in Attachment 7.2 are the same ECGs listed in FSAR Update Table 16.1-1.

A requirement that if an ECG listed in Attachment 7.2 is not complied with, then prior to exceeding the completion time of any required action, a 10 CFR 50.59 evaluation must be approved by the PSRC justifying the acceptability of exceeding the completion time.

Safety Evaluation Summary

The revision to OP1.DC16 places increased administrative controls on ECGs that are relocated from TSs, but does not change the ECG requirements themselves.

44. Setting of the Centrifugal Charging Pump 2-1 Miniflow Orifice Flow Rate
PROC PEP M-223 (Units 1 & 2) (LBIE Log No. 96-046)

Erosion of the centrifugal charging pump (CCP) 2-1 recirculation line restricting orifice resulted in increased flow as measured at power. This procedure measures the flow through the CCP 2-1 recirculation orifice during the CCP full flow performance test in Mode 6. The as-found flow is throttled using a manual valve downstream of the orifice to ensure that CCP 2-1 recirculation orifice design resistance is restored, and to ensure that CCP 2-1 will pass emergency core cooling system (ECCS) flow balance (STP V-15) acceptance criteria. Throttling of the manual valve is not the designed method of preventing excess recirculation flow; therefore, PEP M-223 results in a change to the method of performing the CCP recirculation flow limiting function as described in the FSAR Update.

Safety Evaluation Summary

Throttling the manual valve in the CCP recirculation line to lower recirculation flow will prevent the CCP from exceeding the allowable total pump flow while maintaining the required pump minimum flow. Although the manual valve's design function is to isolate the recirculation line, it will perform as a throttle valve. Restoring the recirculation line design flow resistance will ensure that CCP 2-1 is available to perform its accident mitigation function, and thus maintain the ECCS flow balance.

45. Control Room Vent
AR PK15-06, Rev. 14 (Unit 1) (LBIE Log No. 97-143)

This procedure revision addressed the response to losing both subtrains of control room ventilation system (CRVS) cooling, as described in the FSAR Update. Previously, there was no guidance provided for this event, since there are four equally redundant subtrains available to perform CRVS functions. However, to prevent the possibility of overlooking the FSAR Update described response, these actions were added to the procedure.

Safety Evaluation Summary

Since the proposed procedure revision adds the detail as described in the FSAR Update, there is no change to the facility or operation as described in the FSAR Update. The safety evaluation was performed since the FSAR Update describes response to loss of all CRVS in moderate detail. An unreviewed safety question is not involved.

46. Routine Surveillance Test of PDP 2-3
STP P-PDP-23, Rev. 5 (Units 1 & 2) (LBIE Log No. 97-209)

Operator actions to secure the positive displacement pump (PDP) upon safety injection (SI) actuation were added to allow the surveillance test procedure (STP) to be run with a potential nonconforming condition found in the inadvertent safety injection analysis assumptions.

Safety Evaluation Summary

The procedure revision allowed the PDP to be run with added compensatory measures to mitigate a nonconservative error found in the inadvertent SI analysis. Dedicated operators were required to be stationed in the control room and at the breaker cubical to secure the PDP upon a SI actuation. The inadvertent SI analysis has time critical operator actions in emergency operating procedures (EOPs) to ensure that the pressurizer safety valves will operate within their design and licensing basis. The safety evaluation was required to be performed in accordance with Generic Letter 91-18, Revision 1, which requires a 50.59 review to be performed for any interim compensatory action taken to address a degraded or nonconforming condition. Operator actions were analyzed, in accordance with Information Notice 97-78, to ensure that the actions were adequate to maintain the reactor coolant system within the limits to equipment. The operator actions were determined to be within the training and capability of the operators, and the time allowed in the analysis, and not to affect the performance of operator actions required for EOPs. Potential misoperations were analyzed and determined not to affect plant response to other transients.

47. Environmental Radiological Monitoring Procedure
RP1.ID11, Rev. 33 (Units 1 & 2) (LBIE Log No. 97-193)

In response to a finding from Nuclear Quality Services Audit 962610007, this procedure was revised to include training of personnel responsible for quality-related Radiological Environmental Monitoring Program (REMP) activities, allow the sampling frequencies specified in Table 1 to be extended by 25 percent, and include how training of REMP personnel is to be documented.

Safety Evaluation Summary

The proposed changes to the FSAR Update only involve analysis of environmental samples for the REMP, or editorial changes that do not impact the intent of the FSAR Update. These changes are not accident related, and they do not affect accident analysis or safety-related equipment.

48. Spent Fuel Cooling System
DCM S-13, Rev. 3.2 (LBIE Log No. 96-045)

One sentence in the Design Criteria Memorandum (DCM) was replaced with a paragraph that added clarification and updated detail about the pool water design temperatures assumed in the spent fuel cooling system criticality

analysis. A design memo was referenced that showed that spent fuel pool temperatures could drop to as low as 32°F, well below the minimum ultimate heat sink of the plant. Previously, 68°F was considered the design basis.

Safety Evaluation Summary

A decrease in spent fuel pool temperature has no contribution to the FSAR Update accidents assumed for the spent fuel pool. The contribution to the consequences of an accident is not increased because the resultant K_{eff} remains below the Technical Specification limit of 0.95.

D. Tests and Experiments

1. Continued Operation in Mode 3 with MSSV Inoperable
(Units 1 & 2) (LBIE Log No. 96-028)

This safety evaluation was in response to the August 10, 1996, DCPP unit trips in which main steam safety valves (MSSVs) lifted well beneath set pressure. The safety evaluation covered (in advance) the period of time during which six inoperable MSSVs were tested and reset while the units were in Mode 3. The assumption was that, should a high pressure transient occur during this period, the MSSVs would operate at a lower pressure than set pressure. This was a change in the performance of the MSSVs from that described in the FSAR Update. It was also a condition that might affect safe operation of the plant but was not anticipated or evaluated in the FSAR Update. The safety evaluation also supported a prompt operability assessment.

Safety Evaluation Summary

A lower MSSV opening pressure is a benefit for all FSAR Update accident analyses associated with overpressure protection or minimum heat removal. A review of the accident analysis profile shows that the only FSAR Update accident analyses potentially negatively impacted by the lower pressure are those associated with steam generator tube rupture (SGTR) or overcooling. In the case of SGTR, it was shown that the various effects of Mode 3 operation compared to Mode 1 caused a large enough benefit in SGTR dose and overfill calculations to offset the negative effects of a lower than anticipated lift pressure. In terms of overcooling, the low opening pressure of the MSSVs were bounded by steamline break analyses from a shutdown condition.

2. RCS Flow Calorimetric Beginning of Cycle to End of Cycle
(Units 1 & 2) (LBIE Log No. 97-003)

This procedure describes the performance of a primary to secondary calorimetric and determines the corresponding reactor coolant flowrate. This safety analysis covers the performance of this test at the end of cycle (EOC) operation versus the beginning of cycle (BOC) operation. This was generated as a non-conformance corrective action to document previous EOC testing, and does not describe the current practice of testing at BOC.

Safety Evaluation Summary

The performance of Surveillance Test Procedure (STP) R-26 was moved to EOC to reduce the bias effect of hot leg streaming on the RCS flow measurement. The movement of the STP to EOC and the consequent verification of flow at the beginning of the next cycle using plant indication resulted in larger flow measurement random error and larger RCS loss of flow-low setpoint random

error. The larger errors were determined by calculation and have been addressed in STP R-26 by the application of a flow penalty,which is used to bias the RCS measured flow in the conservative direction. This safety evaluation determined that there is no adverse effect on the DCPP LOCA and non-LOCA safety analyses as a consequence of the flow penalty method. In addition, the RCS flow elbow taps are documented to be reliable for the verification of RCS flow after restart from refueling.

The performance of STP R-26 at EOC provided the requisite level of safety and protection as prescribe in the Technical Specifications.

3. Inservice Testing (IST) Program Plan (Plan) 2nd 10-Year Interval, Revision 12 (Units 1 & 2) (LBIE Log No. 97-050)

This revision included the following changes:

- Removed manual stroke test of RHR-8701 and -8702 from the Inservice Test (IST) Plan P
- Removed several component cooling water (CCW) Header “C” relief valves from IST Plan P
- Removed partial stroke test requirement for emergency core cooling system (ECCS) check valves from IST Plan P

Safety Evaluation Summary

The revision deleted manual stroke test of the residual heat removal (RHR) suction from the reactor coolant system (RCS) hot leg valves RHR-8701 and -8702. Manual operation of these valves is not required because accidents analyzed in the FSAR Update would make the containment building inaccessible and therefore these valves could not be operated post accident.

Several CCW Header ‘C’ relief valves were deleted from the IST Plan P. These valves do not protect vital components, and they only function as relief valves when the subsystem being protected is out of service.

The revision also included removal of the partial stroke test after disassembly requirement from the IST Plan P for several ECCS check valves. NUREG-1482 recommends the partial stroke if practical. The evaluation shows that removal of these items does not create an unreviewed safety question.

4. Containment Fan Cooler Unit (CFCU) Time Delay Relays Replacement Test Preventive Mainteance Testing (PMT) 23.24-23.28 (Unit 2) (LBIE Log No. 97-129)

This item is related to Design Change Package (DCP) E-50344, which replaces the Unit 2 containment fan cooler units (CFCU) time delay timers with more accurate digital type Agastat DSC timers. This evaluation was performed to support the performance of this PMT with the plant in Mode 1.

Safety Evaluation Summary

Testing of the CFCU from the solid-state protection system (SSPS) using a slave relay is not described in the FSAR Update. Also, testing of the CFCU using a simulated auto-transfer signal is not described in the FSAR Update. Connecting the toggle switch across the slave relay contacts does not prevent normal operation of the SSPS slave relay or the auto-transfer relay. Because no engineered safety feature components are disabled during the performance of this test, there is no adverse effect on safety.

5. Commitment Change - Revision of Corrective Action Regarding Main Steam Safety Valve Testing for Notice of Deviation (Inspection Report Nos. 50-275/96-12; 50-323/96-12)
Letter DCL-97-073 (Units 1 & 2) (LBIE Log No. 97-075)

PG&E eliminated an NRC commitment on main steam safety valve (MSSV) testing.In a Safety Evaluation Report dated December 26, 1995, the NRC referenced PG&E's letter of November 1, 1995, in which PG&E described an augmented testing program for the main steam safety valves (MSSVs). PG&E stated in the letter that during the seventh refueling outages for Units 1 and 2, PG&E would obtain valve signature profiles on live steam and with the AVK test equipment. PG&E would also obtain the magnitudes of the AVK test equipment bias. PG&E's intent in collecting this data was to develop valve-specific correction factors (more recently called valve-specific mean seat areas, or MSAs) which would be used to increase the accuracy of setpoint adjustment during MSSV testing. The data to be collected and the derivation of valve specific MSAs for subsequent use in setting MSSVs would be used to establish a means for administrative control over the testing and accurate setting of MSSVs.

The commitment was eliminated because PG&E discontinued the use of the AVK test equipment and methodology (TE&M) in favor of Trevitest TE&M.

Safety Evaluation Summary

The collection of data would have been for the development of valve-specific MSAs for use with AVK TE&M. As the use of valve-specific MSAs with the AVK equipment had demonstrated the inability to assure setting of MSSVs within their Technical Specification limits, the data would not be obtained. The Trevitest equipment and the Trevitest standard MSA had been demonstrated throughout the industry to provide more accurate valve settings. Thus, the Trevitest equipment was selected for use during future MSSV testing rather than AVK.

Therefore, testing and resetting of MSSVs with setpoints meeting the Technical Specification limits did not constitute an unreviewed safety question.

6. Auxiliary Saltwater (ASW) Flow Test Procedure
Surveillance Test Procedure (STP) M-26, Rev. 21 (Unit 1) (LBIE Log No. 97-195)
STP M-26, Rev. 2 (Unit 2) (LBIE Log No. 97-196)

This procedure change revised the frequency of flow testing of the ASW system from monthly to quarterly. This was a change to the frequency as stated in PG&E's responses to Generic Letters 89-13 and 91-13.

Safety Evaluation Summary

The implementation of equipment control guideline (ECG) 17.2 for continuous chlorination, operating experience and inspection results demonstrate that the ASW system is not susceptible to flow degradation due to biofouling, siltation, or coating failure over a quarterly inspection interval.

Continuous chlorination has eliminated growth of biofouling organisms in the ASW system. The design and operation of the ASW system prevent siltation of out of service or inservice piping. Inspection of the ASW pipe and heat exchangers has demonstrated that there is no degradation of the pipe liner material that could block flow.

Based on the above, the increase in the surveillance interval will not create an unreviewed safety question.

7. 4-kV Vital Bus Undervoltage Relay Calibration
Surveillance Test Procedure (STP) M-75, Rev. 18 (Units 1 & 2) (LBIE Log No. 97-165)

Prior to Revision 18, STP M-75 was performed on a deenergized bus with the plant in Mode 5 or 6. Revision 18 provides the necessary precautions and instructions for performing undervoltage relay calibration with the bus energized and the plant in Mode 1. These changes cause the associated diesel generator and bus auxiliary transformer or startup transformer feeders to be inoperable at various times during the test. With extended fuel cycles, this change was necessary to comply with the 18-month calibration frequency required by Technical Specification Table 4.3-2, items 7a and 7b.

Safety Evaluation Summary

Performance of STP M-75 in Mode 1 is an abnormal condition compared to past practice and therefore represents a new plant configuration. Performance of STP M-75 in Mode 1 does not make the 4-kV bus inoperable. Periods of inoperability for the diesel generator and auxiliary or startup feeders are within

the time constraints of Technical Specification action statements. Therefore, Technical Specification requirements and margins of safety are maintained. Performance of the test will not initiate any accidents or plant transients. All FSAR Update Chapter 15 accidents have been evaluated for occurrence with minimum safeguards equipment available. Therefore, there is no unreviewed safety question.

8. Main Steam Safety Valve Testing (STP M-77B)
STP M-77B, (Units 1 & 2) (LBIE Log No. 97-119)

Main steam safety valve (MSSV) discs were replaced with an improved material (Inconel X-750). This necessitated a change to the test procedures allowing the elimination of Mode 1 testing (20 to 30 days after an outage). The testing ensured no sticking following restart with the 422SS MSSV discs. A new STP (STP M-77B) was developed to document the Inconel X-750 test and validation plan and was also designed to minimize test cycling of the valves.

Safety Evaluation Summary

The new material with pre-oxidizing reduces the galling potential and therefore ultimately the sticking of the disc and nozzle within the MSSV. The test plan is an iterative process that ensures continuous valve performance. The reduction of testing and valve cycles serves to improve overall valve performance. Based on these considerations, the probability or consequence of accidents is not affected. Additionally, the improved performance and reduced maintenance cycling reduce the probability and consequence of an equipment failure. The alteration of the disc material and reduction of testing does not introduce new accidents.

9. Boric Acid Inventory
STP R-20, Rev. 18 (Units 1 & 2) (LBIE Log No. 97-194)

This change involved a procedure revision to Surveillance Test Procedure R-20 to implement Plant Staff Review Committee (PSRC) Technical Specification Interpretation 97-05, which increased the minimum refueling water storage tank (RWST) level from 400,000 gal. to 443,455 gal. Also the level indicator reading error penalty was lowered from 5 percent to 2 percent.

Safety Evaluation Summary

PSRC Technical Specification Interpretation 97-05 increases the minimum RWST level to 443,455 gal. This required level increase is due to revisions to the containment recirculation sump level calculations. The level indication post-accident monitoring (PAM) calculation lowered the error penalty from 5 percent to 2 percent for RWST level switches.

10. Plant Process Computer and Manual Operator Heat Balance
Surveillance Test Procedure (STP) R-2B1, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-065)
STP R-2B1, Rev. 1 (Unit 2) (LBIE Log No. 97-066)

The proposed activity is to change the standard test procedure requirement to a check, and reset if required, of the nozzle fouling factor (NFF) for curtailments below 85 percent power. The newly proposed check determines if the existing NFF may continue to be used for the return to 100 percent power. Should the NFF not meet certain criteria, it shall be reset to unity before proceeding to 100 percent power and a new NFF will need to be calculated.

Safety Evaluation Summary

The procedural change for re-establishing or verifying the validity of the NFF does not increase the probability, or change any of the consequences, of an accident previously analyzed in the FSAR Update. This verification of the NFF only aids in assuring that the reactor is operating at the allowable thermal output as licensed.

11. Containment Fan Cooler Unit (CFCU) Timers Setting Verification
TP TB-9627, Rev. 0 (Units 1 & 2) (LBIE Log No. 96-041)

Testing of the containment fan cooler unit (CFCU) from the solid-state protection system (SSPS) using a “simulated” slave relay contact is not described in the FSAR Update. This test procedure describes use of a toggle switch for this test.

Safety Evaluation Summary

Using a simulated signal to start only the CFCU instead of the slave relay requires less equipment to be removed from service to perform this test. All ESF equipment remains in service to mitigate an accident. No engineered safety feature component is disabled for the performance of this test, so there is no increase in the probability of an accident. Therefore, an unreviewed safety question is not involved, and a change to the DCPP Technical specifications is not involved.

12. Component Cooling Water (CCW) to Spent Fuel Pool Heat Exchanger Flow Test
TP TB-9703, Rev. 0 (Unit 1) (LBIE Log No. 97-061)

The purpose of this test is to provide data to evaluate the desirability of proposed future modifications that would increase the heat transfer capacity of the existing spent fuel pool heat exchanger. The test involves increasing the CCW flow from a design flow rate of 3000 gpm to approximately 5000 gpm for no more than five minutes.

Safety Evaluation Summary

This test will not impact the ability to remove decay heat from the reactor core or the spent fuel pool. The test can not impact the operation of the CCW system to any significant extent, nor can it impact the reactivity controls and shutdown margin. No physical modifications will be made to the plant and the design and/or function of the system has not been changed. Based on the above, there is no unreviewed safety question.

13. Cable Spreading Room Pressure Boundary Integrity Verification
TP TB-9711, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-142)

Test Procedure (TP) TB-9711 involves a pressure test on the cable spreading room boundary to determine the amount of leakage present. This test consists of isolating the heating, ventilating, and air conditioning (HVAC) to the room to simulate the conditions present during a CO_2 discharge, and then pressurizing the room to 0.04 in. - 0.06 in. water and cooling by using a fan. The amount of air leaking out of the room will be determined by the installed test equipment.

Safety Evaluation Summary

Isolating the room HVAC will result in a modest rise in ambient temperature above the initial ambient temperature of 80°F. Test conditions require that the cable spreading room be maintained below a maximum limit of 108°F. This temperature limit was conservatively chosen based upon the 120°F operating limit for the Eagle-21 system. Additionally, the maximum allowed test temperature is well below the operating limit of the reactor protection system and electrical equipment in the room. Equipment Control Guideline 23.1 limits the temperature in the cable spreading room to 119°F. In order to maintain the control room habitable during a postulated accident, the test procedure contains instructions to terminate the test in the event of an accident, and to open a door to relieve the pressure. At all times the control room pressurization system will be capable of maintaining a pressure higher than the pressure in the cable spreading room, which will ensure that any leakage is to the outside of the control room.

14. Motor-Operated Valve (MOV) Flow Test - Charging Injection Valves in Mode 5
TP TB-98-2, Rev. 0 (Unit 2) (LBIE Log No. 98-031)

Surveillance Test Procedure (STP) V-15 (ECCS Flow Balance Test) is currently performed in Mode 6 with the reactor vessel head removed. Although dynamic testing of the charging injection Motor Operated Valves (MOVs) 8801A/B & 8803A/B has been previously performed at DCPP, it has been done in Mode 6

under the STP V-15 test conditions. This procedure is written to perform dynamic testing of the valves in Mode 5.

Safety Evaluation Summary

The valves being tested are designed to operate under the conditions established for the test. The charging system is operated within its design parameters during the test, as are the individual components within the system. No material changes are made to the system or components being tested. Low temperature overpressure protection is enabled during testing to address potential overpressurization. Residual heat removal (RHR) system operation is consistent with current Mode 5 or 6 operation of the system. By using the operable centrifugal charging pump , the required boration flowpath is maintained throughout the test. RHR flow continues to provide reactor coolant system cooling during the test.

Since no material changes are made to the system, and system and component operation is within design parameters and Technical Specification limitations, the test does not involve an unreviewed safety question.

E. Equipment Control Guidelines

1. Administrative Changes to ECGs
   ECG 0.0, Rev. 3 (LBIE Log No. 97-103)
   ECG 7.7, Rev. 1 (LBIE Log No. No. 97-109)
   ECG 17.3, Rev. 1 (LBIE Log No. No. 97-110)
   ECG 23.1, Rev. 1 (LBIE Log No. 97-111)
   ECG 39.6, Rev. 1 (LBIE Log No. 97-112)
   ECG 99.9, Rev. 1 (LBIE Log No. 97-113)
   ECG 4.3, Rev. 1 (LBIE Log No. 97-104)
   ECG 7.3, Rev. 2 (LBIE Log No. 97-105)
   ECG 7.4, Rev. 1 (LBIE Log No. 97-106)

   In PG&E's Letter DCL-95-222, dated October 4, 1995, PG&E submitted License Amendment Request (LAR) 97-07 that proposed to relocate several Technical Specifications (TSs) to Equipment Control Guidelines (ECGs) and to reference the ECGs in the FSAR Update. During review of LAR 97-05, the NRC staff requested PG&E to add the following wording to FSAR Update Section 16.1: "ECGs containing relocated TSs are incorporated into the FSAR Update, by reference, in Table 16.1-1. For ECGs listed in Table 16.1-1, if the equipment cannot be returned to service as required by the ECG, then a review in accordance with 10 CFR 50.59 is required."

   PG&E made these changes to the FSAR Update, and incorporated them into the existing ECGs listed in FSAR Update Table 16.1-1 by adding the following note to each ECG: "Prior to exceeding the Completion Time of any Required Action, a 10 CFR 50.59 evaluation must be approved by the PSRC justifying the acceptability of exceeding the Completion Time."

   Safety Evaluation Summary

   The revision to ECGs relocated from TSs places increased administrative controls on obtaining approval to exceed completion times for required actions but does not change the ECG requirements themselves. By requiring Plant Staff Review Committee approval of a 10 CFR 50.59 safety evaluation for an extension of a completion time for a required action, assurance is provided that the extension will not involve an unreviewed safety question.

2. Equipment Control Guidelines Applicability
   ECG 0.0 & 0.0, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-029)

   This issue concerns opposite wording between Equipment Control Guidelines (ECG) 0.4 and Technical Specification (TS) 3.0.4 regarding allowance of mode transitions. The less restrictive wording of ECG 0.4 could have permitted mode transitions which would not have been permitted under the more restrictive wording of TS 3.0.4. However, a review identified no actual instances where the

plant has been in an ECG shutdown action statement. The ECG 0.4 wording problem will be corrected by a revision to the ECG.

Safety Evaluation Summary

Because this change is a revision to an ECG, Procedure OP1.DC16 requires a 50.59 safety evaluation. The ECG revision involved revising ECG 0.4 to more restrictive language regarding allowance of mode transitions to agree with TS 3.0.4. The probabilities of occurrence of an accident or consequences are not increased. The probability of occurrence of a malfunction of equipment important to safety previously evaluated is not increased. A new type of accident is not created. The margin of safety as defined in the Technical Specifications is not reduced.

3. Post Accident Sampling System
ECG 11.1, Rev. 5 (Unit 1) (LBIE Log No. 97-004)

This Equipment Control Guideline (ECG) revision changes the Mode Applicability requirements for monitoring reactor coolant for dissolved hydrogen from "with fuel in containment" to "Modes 1 through 4." In addition, this revision clarifies the Technical Specification bases to reference the Unit 1 PG&E letter to NRC and reference Surveillance Test Procedure (STP) G-14, Rev. 1, as the original acceptance criteria document for post-accident sampling.

Safety Evaluation Summary

This ECG revision is an administrative change only, and does not involve any physical changes to the post-accident sampling system (PASS) or dissolved hydrogen monitors. It only affects the mode applicability requirements of a plant monitoring instrument. The dissolved hydrogen monitors will continue to function post-loss-of-coolant accident in accordance with NUREG-0737 and Regulatory Guide 1.97 when indication of dissolved hydrogen content in the reactor coolant system (RCS) is required for accident monitoring purposes.

The capability to obtain and analyze RCS samples under accident conditions will be maintained as a result of this ECG revision. This change does not affect the operation of any safety-related systems or equipment and does not introduce any new failure modes for any equipment in the PASS or any safety-related system component or equipment. This change does not affect Technical Specification 6.8.4.e, "Post accident Sampling." Therefore, there is no reduction in the margin of safety.

4. Post Accident Sampling System
ECG 11.1, Rev. 6 (Units 1 & 2) (LBIE Log No. 97-170)

The revision to Equipment Control Guideline (ECG) 11.1 added a note to the actions to include the reporting requirement in Facility Operating License DPR-80, Section 2.G. In accordance with the provisions of 10 CFR 50.72, the NRC must be notified within 24 hours when the post accident sampling system and its alternate sampling methods are not available, with written follow-up in accordance with the provisions of 10 CFR 50.73.

Safety Evaluation Summary

A safety evaluation was performed because revision of an ECG requires a safety evaluation. This revision is an administrative change to make the reporting requirement more visible to the Operations staff. The reporting requirement was removed from Surveillance Test Procedure G-4 and placed in ECG 11.1 and Procedure XI1.ID2.

5. Equipment Control Guideline: CCW Surge Tank Pressurization System
ECG 14.1, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-074)

ECG 14.1 was developed and implemented in 1996 to place administrative controls on the newly installed component cooling water (CCW) surge tank pressurization system. In 1997, PG&E elected to convert the ECG to a technical specification and submitted License Amendment Request (LAR) 97-05 to accomplish this (Reference DCL-97-074, dated May 22, 1997). In developing the LAR, a more conservative allowed outage time (AOT) was defined, and an additional surveillance requirement was identified. Revision 2 to ECG 14.1 was issued to have the ECG requirements coincide with the proposed LAR.

Safety Evaluation Summary

Revisions 0 and 1 to ECG 14.1 were approved to establish controls to assure that the CCW pressurization system and the CCW system are capable of performing their required functions. Revision 2 to ECG 14.1 reduces the AOT for the surge tank pressurization system from 7 days to 12 hours based on a probabilistic risk assessment. The CCW pressurization system is designed to mitigate an accident and is not an accident initiator. ECG 14.1 establishes administrative requirements and the proposed changes, including the reduction in the AOT, will not affect the method of operation of the CCW system or the method by which the CCW system performs its function.

6. Fire Suppression Systems/Fire Suppression Water Systems
ECG 18.1, Rev. 4 (Units 1 & 2) (LBIE Log No. 97-199)

This Equipment Control Guideline (ECG) revision extends the urveillance frequency for testing fire suppression valves as specified in the ECG Surveillance Requirement 18.1.8 (valves not testable during plant operation) from 18 months to 24 months to be consistent with 24-month fuel cycles.

Safety Evaluation Summary

This change does not alter the way any important to safety structure, system, or component functions, and does not change the manner in which the plant is operated. Increasing the surveillance interval of the fire water valves not testable during plant operation will not alter the operation of the fire water system or the intent or method by which the surveillance is presently conducted. The operability of the fire water valves is not affected by the surveillance interval change as these valves are maintained in the sealed open position to ensure a water source is always available.

This change does not result in a physical modification to either the valves or any important-to-safety system, structure, or component. The fire water valves and fire water system are not addressed in any Technical Specifications or associated with any margin of safety. Since the increased surveillance frequency does not impact the operation of the fire water system, this change does not involve a reduction in margin of safety as defined in the Technical Specifications.

7. Fire Hose Stations
ECG 18.2, Rev. 5 (Units 1 & 2) (LBIE Log No. 97-200)

Revision to Equipment Control Guideline (ECG) 18.2 changes the surveillance requirement frequency of fire hose inspections for hose stations not accessible during plant operation from 18 months to at least once per refueling interval (24 months).

Safety Evaluation Summary

With the inspection interval extended 6 months, the hoses and valves remain qualified to perform their intended functions. As a result, inadvertent introduction of fire water into containment is not considered a credible event due to hose aging and subsequent failure.

8. Fire Hose Stations
ECG 18.2, Rev. 4 (Units 1 & 2) (LBIE Log No. 97-173)

Equipment Control Guideline (ECG) 18.2 Surveillance Requirement 18.2.6 required that hose hydrostatic tests be conducted every 3 years at a pressure of 150 psig or at least 50 psig above the maximum fire main operating pressure, whichever is greater. This change would revise the hydrostatic test pressures to conform with the requirements of National Fire Protection Association (NFPA) Standard 1962, "Care, Use and Service Testing of Fire Hose Including Couplings and Nozzles." NFPA 1962 requires that the hoses be tested to 150 psig, consistent with the current requirements.

Safety Evaluation Summary

Fire hoses are not accident initiators, therefore the probabilities of occurrence and the consequences of an accident are not increased. The design of any equipment important to safety, the method by which any equipment important to safety performs its required function, and the operation of equipment important to safety are not affected. Therefore, no accident consequences are increased, no new accidents are created, no new types of equipment malfunctions created and there is no reduction in the margin of safety as defined in the basis for any Technical Specifications.

9. Fire Hose Stations
ECG 18.2, Rev. 3 (Units 1 & 2) (LBIE Log No. 96-007)

The revision to Equipment Control Guideline (ECG) 18.2 on Fire Hose Stations added operability requirements for two existing fire hose stations located in the intake structure. The fire hose stations are now credited as part of the fire protection for 10 CFR 50, Appendix R circuits to the auxiliary saltwater pumps.

Safety Evaluation Summary

The revisions made to the ECG provide guidance in controlling the operation of the fire hose stations located in the intake structure. Accidents analyzed in the FSAR Update are unaffected and operability of equipment important to safety is not impacted. Therefore, the change does not involve an unreviewed safety question.

10. Fire Detection Systems
ECG 18.3, Rev. 3 (Units 1 & 2) (LBIE Log No. 96-008)

This revision to Equipment Control Guideline (ECG) 18.3 on Fire Detection Systems changed a note regarding the heat sensors that actuate the carbon dioxide flooding systems in the intake structure. The note changed a reference to a new section that was added to ECG 18.5 (CO_2 Systems). The CO_2 System and its heat sensor are now credited as part of the fire protection for 10 CFR 50. Appendix R circuits to the auxiliary saltwater pumps.

Safety Evaluation Summary

The changes made to the ECG provide administrative controls for fire protection features credited to protect one train of redundant safe shutdown circuits. By including these fire protection features into ECGs, adequate compensatory measures are provided should these systems be impaired. The addition of fire suppression and detection systems into existing ECGs does not affect the function of equipment important to safety. By including these fire protection features into the ECGs, stricter surveillance requirements are implemented and compensatory measures are implemented should these systems become impaired. Based on the above criteria and justification, an unreviewed safety question is not involved.

11. Spray and/or Sprinkler Systems
ECG 18.4, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-192)

This Equipment Control Guideline (ECG) deletes ECG Surveillance Requirement (SR) 18.4.5. The current requirements specify cycling each valve in the flow path that is not testable during plant operation. The only plant valves in these systems that fall into this category are located inside the containment. These valves are already covered by ECG 18.1.8. Thus ECG 18.4.5 is a duplicate and is not required.

Safety Evaluation Summary

This change does not affect the way any important to safety structure, system, or component functions, nor does it change the manner in which the plant is operated. The elimination of the surveillance requirement of ECG 18.4.5 for the fire water valves does not have any impact on plant equipment because it is a duplicate of the requirements of ECG 18.1.8. The operability of the fire water valves is not affected by eliminating this surveillance requirement because the only valves not testable during plant operation are located inside the containment and are covered by ECG 18.1.8.

The fire water valves and fire water system are not addressed in any Technical Specification or associated with any margin of safety. This change does not impact the operation of the fire water system or the fire water valves. Therefore, it does not involve a reduction in the margin of safety as defined in the Technical Specifications.

12. CO_2 Systems
ECG 18.5, Rev. 3 (Units 1 & 2) (LBIE Log No. 97-201)

This Equipment Control Guideline (ECG) revision extends the frequency for ECG Surveillance Requirement (SR) 18.5.2.5 from 18 months to at least once per refueling interval (24 months). Performance of this SR during refueling outages is specified due to the personnel safety associated with entering the circulating water pump (CWP) motor cubicle to perform this SR during power operation.

Safety Evaluation Summary

The high pressure CO_2 system is designed to mitigate a fire and is not an accident initiator. The system is provided to suppress oil fires internal to the CWP motor housing. This change does not alter the way any important-to-safety structure, system, or component functions, nor does it change the manner in which the plant is operated. Increasing the surveillance interval for the high pressure CO_2 detection system does not result in any physical modifications to either the detection system or any important to safety structure, system, or component. This change does not alter the intent or method by which the surveillance is presently conducted.

The high pressure CO_2 detection system is not addressed in any Technical Specification or associated with any margin of safety. The increased surveillance frequency does not impact the operation of the detection or suppression system. Therefore, this change does not involve a reduction in margin of safety as defined in the basis for any Technical Specification.

13. CO_2 Systems
ECG 18.5, Rev. 2 (Units 1 & 2) (LBIE Log No. 96-009)

This revision Equipment Control Guideline (ECG) 18.5 on carbon dioxide systems added operability requirements for the high pressure CO_2 system at the intake structure. The CO_2 System is now credited as part of the fire protection for 10 CFR 50, Appendix R circuits to the auxiliary saltwater pumps.

Safety Evaluation Summary

The high pressure CO_2 system in the intake structure is credited to suppress the combustible materials located in the circulating water pump (CWP) motor housings. This suppression system protects at least one train of auxiliary saltwater (ASW) pump and exhaust fan circuits against the highest fire hazards in the area. As a backup suppression system, a sprinkler nozzle is also installed above one train of ASW pump and exhaust fan circuits to ensure that one train will remain available for safe shutdown in the event of a fire. Either the CO_2 system or the sprinkler head, in conjunction with local smoke detection, manual fire suppression, and "No Storage of Combustible Material" zone, will provide

adequate protection such that one train of ASW pump and exhaust fan circuits will be available for safe shutdown in the event of a fire in Fire Area IS-1/Fire Zone 30-A-5 (Reference DCPP Fire Hazards Appendix R Evaluation (FHARE) 110 and FSAR Update Appendix 9.5A).

14. Multiple Procedure Change
ECG 18.6 - Recission, ECG 18.1, Rev. 3, and ECG 18.1, Rev. 4, (Units 1 & 2) (LBIE Log No. 97-174)

Equipment Control Guideline (ECG) 18.6 was rescinded because the Halon fire suppression system was removed from the solid state protection system (SSPS) room. ECG 18.1 was revised to delete the reference to Halon. The detection panel alarms, and ventilation damper controls associated with the Halon suppression system were not removed. Surveillance testing of this part of the system was unchanged. The testing requirements were relocated to ECG 18.3.

The Halon fire suppression system was removed from the SSPS room because the Halon fire suppression system is no longer necessary to provide automatic fire suppression to the SSPS room. Current analysis assumes the loss of an SSPS train as the result of a fire. Manual actions and redundant safe shutdown components are credited for mitigating the effects of a fire in this area. Halon is no longer commercially available due to environmental concerns over release of hydrofluorocarbons into the atmosphere.

Physical changes were made by DCP M-049295/050295, Rev. 0.

Safety Evaluation Summary

This 10 CFR 50.59 safety evaluation was prepared because OP1.DC16 requires a safety evaluation for all ECG revisions.

In a meeting on January 30, 1997, the NRC concurred with PG&E's approach to evaluate and remove the Halon system based on DCPP license conditions and on performance of a 50.59 safety evaluation.

The safety evaluation performed for this ECG change is based on the evaluation performed for Design Change Packages (DCPs) M-049295 and M-050295 and approved by the DCPP Plant Staff Review Committee (PSRC) on August 13, 1996.

The Halon fire suppression system is designed to mitigate the consequences of a fire. Removal of the SSPS room Halon suppression system does not change combustible loading or ignition controls in the SSPS room. The design basis accident is a fire, and removal of the SSPS room will not increase the probability of a fire in the SSPS room or any other fire area.

Consequences of a fire in the SSPS room are not increased by removal of the Halon system because current analysis assumes loss of a SSPS train as a result of a fire. The safe shutdown analysis credits operators with manually tripping the reactor from the control room. DCPP Fire Hazards Appendix R Evaluation (FHARE) 112 credits manual actions and redundant safe shutdown components for mitigating the effects of a fire in this area, and for providing the capability to achieve and maintain safe shutdown.

Possibility, probability, and consequences of other accidents or equipment malfunctions are not increased. Once the reactor is tripped, equipment in the SSPS is not required to maintain safe shutdown. If there is a fire in the SSPS room, FHARE 112 credits operator action to trip the reactor from the control room.

15. <u>Fire Rated Assemblies</u>
ECG 18.7, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-202)

This Equipment Control Guideline (ECG) revision modifies Surveillance Requirement (SR) 18.7.1 to extend the frequency for inspecting fire rated assemblies inside containment from every 18 months to every 24 months to be consistent with 24 month refueling cycles. Performance of this surveillance is necessary due to the rated enclosures being located in the containment and as low as is reasonably achievable (ALARA) considerations.

Safety Evaluation Summary

Fire rated assemblies are designed to mitigate the consequences of fires and do not cause an accident. This change does not alter the way any important-to-safety structure, system, or component functions, nor does it change the manner in which the plant is operated. Increasing the surveillance interval for the containment fire related enclosures does not result in any physical modifications to either the barrier or any important to safety structure, system, or component. This change does not alter the intent, scope, or method by which the surveillance is presently conducted.

The fire rated assemblies are not addressed in any Technical Specification (TS) or associated with any margin of safety. The increased surveillance frequency does not impact the operation of any fire protection system or component, and does not affect the operation of equipment protected by the enclosure. Therefore, this change does not involve a reduction in margin of safety as defined in the TS.

16. Radioactive Liquid Effluent Monitoring Instrumentation
ECG 39.3, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-148)

This Equipment Control Guideline (ECG) changes the channel check frequency for the Oily Water Separator (OWS) Flow Recorder (FR)-251, as required by Surveillance Requirement (SR) 39.3.1, from “24 Hours” to “daily.” This change is needed to eliminate some unnecessary OWS manual pump downs that are done only to perform the FR-251 channel check.

Safety Evaluation Summary

Changing FR-251 channel check frequency from 24 hours to daily does not change the way that FR-251 performs its required function. FR-251 does not initiate an accident, but is intended to provide a flow measurement in the event radioactive material is released due to some other condition in the plant. The daily channel check will provide, over time, the same number of required periodic channel checks as the current requirement.

The maintenance history of FR-251 shows that this instrument is very reliable. Since corrective maintenance was last performed on the instrument in 1992, it has passed all of its quarterly functional surveillance tests satisfactorily. Consequently, FR-251 is not expected to fail in between channel checks, even if they are performed as much as 48 hours apart over a two day period. There are no Technical Specification (TS) requirements or TS bases for the OWS. Therefore, there is no reduction in the margin of safety.

17. ATWS Mitigation System Actuation Circuitry
ECG 4.1, Rev. 2XPR (Units 1 & 2) (LBIE Log No. 97-188)

This Equipment Control Guideline (ECG) revision changes the applicability from Mode 1 above 40 percent turbine power to Mode 1 above 40 percent reactor power. This change brings ECG 4.1 into compliance with the licensing basis for the anticipated transient without scram (ATWS) mitigation system actuation circuitry (AMSAC) system. The licensing basis is contained in the safety evaluation for the AMSAC system. The safety evaluation assumes AMSAC is armed when reactor power is above 40 percent. The current AMSAC arming setpoint (C-20) of 40 percent turbine power is equivalent to approximately 46 percent reactor thermal power (RTP). The current AMSAC setpoint is within the design limits of the system, but is not within the licensing basis which assumes 40 percent RTP.

Safety Evaluation Summary

AMSAC is designed to mitigate the consequences of an ATWS event and is not an accident initiator. An ATWS event is not a design basis event analyzed in FSAR Update Chapter 15, but AMSAC is a licensing requirement specified by 10 CFR 50.62 and is documented in the FSAR Update. This change does not affect the design or configuration of AMSAC, but changes the alarming setpoint to agree with the AMSAC safety evaluation. There is no change in the way AMSAC operates other than the power level at which it becomes armed. This change restores the assurance that the fuel cladding will perform its required function. This change reduces the potential for voiding in the reactor vessel in the event of an ATWS, thereby assuring that the fuel remains cooled.

AMSAC is not addressed in the Technical Specifications, but this change lessens the consequences of an ATWS event and increases the margin of safety.

18. Steam Generator Level and Pressure Instruments (Appendix R) - Surveillance Requirement 4.2.2
ECG 4.2, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-159)

This Equipment Control Guideline (ECG) change revises the steam generator (SG) level and pressure instruments surveillance requirements (SRs) to change the surveillance frequency from at least once every 18 months to at least once per refueling interval. The SG instrumentation covered by this ECG provides alternate monitoring and indication capability in the event of a fire in the control room or the cable spreading room.

Safety Evaluation Summary

This change does not alter the way any important to safety structure, system, or component (SSC) functions, nor does it change the manner in which the plant is operated. There are no physical modifications to either the SG level and pressure instruments or any important-to-safety SSC. Increasing the surveillance interval does not alter the operation of the instruments, the intent or the method by which the surveillance is conducted, or the scope or intent of the associated surveillance test procedures. It does not adversely affect safety function performance, or alter the intent or method by which surveillance tests are performed.

The instruments will continue to effectively perform their design function for the longer operating cycles, and there is no time dependency associated with the encountered component failures. There is inherent substantial redundancy and other periodic checks that help ensure sufficient availability of these instruments to perform their design functions. These instruments are not required to be operable by the Technical Specifications. Therefore, this change does not involve a reduction in the margin of safety.

19. Technical Support Center ERDS
ECG 52.2, Rev. 2 (Units 1 & 2) (LBIE Log No. 96-031)
ECG 52.3, Rev. 1 (Units 1 & 2) (LBIE Log No. 96-032)

Design Change Packages (DCPs) J-49246 and J-50426 establish the emergency response facility data system (ERFDS) within the plant process computer (PPC). The PPC performs the functions of data acquisition, display, recording and recall as required by DCPP commitments to NUREG-0696 and NUREG-0737, Supplement 1. This change is made to upgrade the data systems with equipment that performs the required functions, with high reliability.

Safety Evaluation Summary

A PPC subsystem, ERFDS, is a monitoring system isolated from the plant input instrumentation. These systems do not control plant equipment and are electrically isolated from data input uses. The PPC/ERFDS provide data to the control room, technical support center, and emergency operations facility during accident response and is used as input in decision-making following accidents. The PPC/ERFDS cannot create an accident or cause a malfunction of equipment important to safety. There is no decrease in the margin of safety.

20. Reactor Coolant System (RCS) Instrumentation (Appendix R)
ECG 7.1, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-150)

This Equipment Control Guideline (ECG) change revises the reactor coolant system (RCS) instrumentation (Appendix R) ECG Surveillance Requirement

(SR) 7.1.2 to change the surveillance frequency from at least once every 18 months to at least once per refueling interval. The pressurizer pressure and pressurizer level instrument channels covered by this ECG are located on the dedicated shutdown panel (DSP). These devices provide alternate monitoring and indication capability in the event of a fire in the control room or the cable spreading room.

Safety Evaluation Summary

This change does not alter the way any important-to-safety structure, system, or component (SSC) functions and does not change the manner in which the plant is operated. There are no physical modifications to the instrument channels, or to any SSC. Increasing the surveillance interval does not alter the operation of these instrument channels, the intent or the method by which the associated surveillances are conducted, or the scope or intent of the associated surveillance test procedures. It does not affect safety function performance, or alter the intent or method by which surveillance tests are performed.

The instrument channels will continue to effectively perform their design function for the longer operating cycles. There are no indications that any of the identified RCS instrumentation failures are cycle-length dependent. There is no safety analysis impact since this change does not affect any safety limit, protection system setpoint, or limiting condition for operation.

21. Power-Operated Relief Valve (PORV) Emergency Close at the Hot Shutdown Panel (HSP) (10 CFR 50, Appendix R) - Surveillance Requirement 7.2.1
ECG 7.2, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-151)

This Equipment Control Guideline (ECG) change revises the PORV emergency close at the HSP (Appendix R) ECG surveillance requirement (SR) to change the surveillance frequency from at least once per 18 months to at least once per refueling interval. The PORV emergency close control circuits covered by this ECG provide an alternate method of closing the PORVs in the event of a fire in the control room and/or the cable spreading room.

Safety Evaluation Summary

This change does not alter the way any important to safety structure, system, or component (SSC) functions and does not change the manner in which the plant is operated. There are no physical modifications to the control circuitry, or to any SSC. Increasing the surveillance interval does not alter the operation of these control circuits, the intent or the method by which the associated surveillances are conducted, or the scope or intent of the associated surveillance test procedures. It does not affect safety function performance, or alter the intent or method by which surveillance tests are performed.

The PORV emergency close control circuits will continue to effectively perform their design function for the longer operating cycles. No failures have been encountered during the functional testing of this circuitry, and there is no evidence that the performance of these control circuits is time dependent or that the longer surveillance interval will adversely affect the performance of these switches.

22. Safety Valves - Shutdown
ECG 7.3, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-079)

Revision 1 to Equipment Control Guideline (ECG) 7.3 updates the ECG Bases to document the current method for testing pressurizer safety valves. The valves are tested in accordance with Westinghouse report WCAP 12910, Rev. 1A, "Pressurizer Safety Valve Set Pressure Shift," dated March 1993.

Safety Evaluation Summary

Revision 1 to ECG 7.3 updates the ECG Bases to reflect the current approved method for pressurizer relief valve testing. The revision does not modify the ECG itself. The ECG 7.3 requirements were relocated from Technical Specifications as approved by License Amendments 98/97. Therefore the ECG Bases revision does not involve an unreviewed safety question.

23. Positive Displacement Pump (PDP)
ECG 8.1, Rev. 3 (Units 1 & 2) (LBIE Log No. 97-171)

This Equipment Control Guideline (ECG) revises the allowed outage time (AOT)from 7 days to 14 days each calendar year to perform overhaul work on the positive displacement pump (PDP). A 7-day AOT does not allow sufficient time to perform an overhaul, without obtaining an AOT extension.

Safety Evaluation Summary

The increased AOT from 7 days to 14 days once per year to overhaul the pump does not change the operating methods or practices for the PDP. The increased

AOT does not result in any changes to hardware or equipment associated with the PDP. It will continue to operate and be operated as it is currently. The PDP is not an accident initiator, but is designed to allow the plant to achieve safe shutdown if a fire were to occur in the centrifugal charging pump (CCP) room such that both CCPs were disabled. The increased AOT to allow the performance of maintenance will increase the overall reliability of the PDP.

The PDP is not Technical Specification required equipment and is not credited in any FSAR Update Chapter 15 design basis accident analysis as mitigation equipment. Therefore, the increased AOT will not result in a reduction in the margin of safety as defined in the basis for any Technical Specification.

24. Centrifugal Charging Pump (CCP) Backup Firewater Cooling
ECG 8.3, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-009)

This change creates a new Equipment Control Guideline (ECG) to provide administrative controls for backup firewater cooling to CCPs. An analysis that supports the DCPP Security Plan takes credit for the CCP backup firewater cooling system to meet vehicle barrier security requirements.

Safety Evaluation Summary

The CCP backup firewater cooling system is a design feature that allows the CCPs to provide cooling to the reactor coolant pump (RCP) seals in the event of complete loss of auxiliary saltwater (ASW) system. It is a mitigation system and not an accident initiator. However, it is not credited in the FSAR Update for mitigating any accident.

This new ECG places existing administrative controls for the CCP backup firewater cooling system, plus a new monthly surveillance requirement (visual inventory), under the controls of the ECG program specified by procedure OP1.DC16. The only equipment important to safety affected by these controls are the CCPs.

Creation of the ECG and its associated surveillance requirements (SRs) provides assurance that consequences of loss of both ASW trains due to vehicle damage of the trains will not increase the probability or the consequences of a small break loss-of-coolant accident by assuming that this backup method of cooling the CCPs, and consequently the RCP seals, is available. None of these controls are included in Technical Specifications. Therefore, there is no reduction in margin of safety as defined in the basis for any Technical Specification.

25. Safety Injection – Accumulator Pressure and Water Level Instrumentation
ECG 9.1, Rev. 1 (Units 1 & 2) (LBIE Log No. 96-040)

This Equipment Control Guideline (ECG) revision makes a distinction between surveillance requirements for narrow range (NR) and wide range (WR) safety injection (SI) accumulator water level channels. Previously, ECG Surveillance Requirement (SR) 9.1.1 required a channel functional test (CFT) on a 31-day frequency for pressure and NR level channels, but did not apply to WR level. However, WR level is part of Regulatory Guide 1.97 post accident monitoring (PAM) requirements. Other PAM instruments receive a channel calibration on a refueling outage frequency (18 months in Rev. 1; 24 months in Rev. 2). SR 9.1.2 was clarified to add WR level channel calibration on an 18-month frequency.

Safety Evaluation Summary

The SI accumulator WR level channels are for PAM indications only. They do not provide input to any engineered safeguards features (ESF) function required for accident mitigation. Neither can the channels initiate any accident. The channels are used following an accident to provide a qualitative indication of whether an accumulator has injected. The indication itself has no effect on the consequences or management of an accident.

Clarification of SI accumulator WR level surveillance requirements has no impact on the frequency or consequences of any accident or equipment malfunction as evaluated in the FSAR Update. The WR level channels are not part of any Technical-Specification-required function and are not used to establish operating level in the accumulators; there is no impact on any Technical Specification safety margin.

26. Snubbers
ECG 99.1 (Units 1 & 2) (LBIE Log No. 97-085)

This Equipment Control Guideline (ECG) change was performed to alter the snubber functional testing frequency from 18 to 24 months during shutdown to coincide with the 24-month fuel cycle.

Safety Evaluation Summary

This change in surveillance frequency was determined to be in compliance with the ASME/ANSI OM Part 4, OMa-1988 addenda to the OM-1987 Edition, which states: "Testing shall take place at least every refueling outage using a sample of snubbers." In 1993 an ASME/ANSI OM-4 task group completed a review of the surveillance frequency, in light of reactor facilities extending fuel cycles to 24 months and concluded the code is applicable for the 24-month cycle. A review of the test results from the most recent nine refueling outages at DCPP showed a test failure rate of less than 1 percent and in all those cases the piping had remained operable with the failed snubber. This low testing sample failure rate and the ANSI OM-4 study showed that the proposed frequency will maintain a high confidence level in snubber operability.

27. Snubbers
ECG 99.1, Rev. 3 (Units 1 & 2) (LBIE Log No. 97-187)

This Equipment Control Guideline (ECG) revises the surveillance frequency for functional testing and service life monitoring of snubbers, as specified in Surveillance Requirements (SRs) 99.1.3 & 99.1.7, from 18 months to 24 months to be consistent with 24-month fuel cycles.

Safety Evaluation Summary

Snubbers are designed to limit pipe movement during design basis seismic events and are not accident initiators. This change does not affect the way in which the snubbers operate. Also, this change complies with the ASME/ANSI OM Part 4 code requirements.

A review of snubber operational, maintenance, and surveillance testing history has demonstrated that the snubbers are reliable and can be expected to perform their required function when tested on a 24-month interval. The snubber test failure rate has been less than 1 percent over the past nine refueling outages and in each case of snubber test failure, the piping analysis has shown that the piping remained operable. This low sample test failure rate combined with additional tests performed for service life monitoring provides a high confidence level in snubber operability using the sampling test methods prescribed in ASME/ANSI OM Part 4. Therefore, this change does not involve a reduction in margin of safety as defined for any Technical Specification.

F. FSAR Update Changes

1. NIS Detector Description
FSAR Update 4.4.5.3 (LBIE Log No. 98-002)

FSAR Update Section 4.4.5.3 describes the positioning of the nuclear instrumentation system (NIS) detectors around the reactor core. This section states, "The two positions opposite the other two flat positions of the core are spare instrumentation wells." These instrumentation wells in fact house the post-accident neutron flux monitor detectors.

Safety Evaluation Summary

This FSAR Update change corrects the description of the NIS detector well arrangement. No physical modifications or design changes are required. There is no accident evaluated in the FSAR Update that is affected by changing the description of the NIS detector placement. Equipment operation and function remains the same. No technical specifications changes are required. The margin of safety is not affected by changing the NIS detector placement description in the FSAR Update.

2. Change Testing Methodology for P-8 Blocking Function
FSAR Update 7.2.2.2.1.7(2) (LBIE Log No. 98-001)

The testing description in FSAR Update Section 7.2.2.2.1.7 was changed to reflect the manner in which the P-8 blocking function is tested. This was required when it was discovered that the P-8 block is not tested by the SSPS semi-automatic tester. A commitment was made in PG&E letter DCL-97-172 to test the P-8 function using other means, a description of which was added to FSAR Update Section 7.2.2.2.1.7.

Safety Evaluation Summary

The FSAR Update change clarifies the test method described in the FSAR Update. The additional testing to verify the P-8 block function is performed when the solid-state protection system (SSPS) train is removed from service. No accidents previously evaluated are affected by clarifying the SSPS test methodology. Since testing is performed with the SSPS train out of service the probability of a malfunction of equipment important to safety is not increased. No physical modifications are performed. No Technical Specification changes are required. The additional testing satisfies the requirements of Technical Specification 4.3-1, item 22.

3. Subcooled Margin Monitor
AR A0427405 (LBIE Log No. 97-067)

This change corrects information in FSAR Update Table 7.5-5, “Information Required on the Subcooling Meter,” concerning:

- The uncertainty of the input parameters (reactor coolant system (RCS) coolant temperature and pressure)
- The uncertainty in the digital readout meter
- The range of RCS pressures that the digital readout meter uncertainty is applicable

Safety Evaluation Summary

The uncertainty (input signals and digital readout) information was updated to reflect the calculations revised as part of the Extended Fuel Cycle project. These calculations used DCPP specific calibration data to model equipment performance for both 18- and 24-month fuel cycles. The digital readout meter uncertainty applicability limitation was added based on a 1986 Westinghouse commitment to the NRC on subcooled margin monitor (SMM) accuracy requirements.

The proposed changes to the FSAR Update Table 7.5-5 accuracy statements provide an envelope for the expected control room indication uncertainty. The proposed changes will provide realistic control room indication accuracy statements in compliance with the requirements of Regulatory Guide (RG)1.70, Revision 1. An evaluation of the control room indication accuracy has been performed as follows:

The text of the FSAR Update does not indicate that range and accuracy information included in Table 7.5-5 is based on an operational requirement of DCPP. However, the PG&E has evaluated the proposed changes with respect to the design requirements established in DCPP design basis documents. This evaluation identified no adverse impact on the design bases of DCPP.

4. Substitution of Alternate Fire Protection Features for Unqualified 3-Hour Fire Barrier
FSAR Update Appendices 9.5A and 9.5H (LBIE Log No. 96-006)

The qualification of the Pyrocrete and 3M material used as a 3-hour fire barrier was determined to be questionable. 10 CFR 50, Appendix R, Section III.G.2.b, allows crediting other means of meeting the required separation of redundant circuits credited for safe shutdown in the event of a fire. Specifically it allows crediting a 20-foot horizontal separation with no intervening combustibles or fire hazards, coupled with installation of fire detectors and an automatic fire suppression system in the fire area. All of these alternate requirements are met for the auxiliary saltwater (ASW) pump and exhaust fan circuits in Fire Area IS-

1/Fire Zone 30-A-5.. These include local smoke detectors, overhead sprinkler heads, and local heat-activated carbon dioxide suppression systems. To ensure the operability of these detectors and suppression systems that are now being credited to meet Appendix R requirements in lieu of the 3-hour fire barrier, they have been brought under formal administrative control by adding them to the appropriate equipment control guideline

Safety Evaluation Summary

Meeting these alternate requirements ensures that at least one of the redundant ASW trains in each unit will remain operable in the event of a fire at any location in the fire area. There is no decrease in safety because in the event of a fire, the NRC has determined that the alternative measures being instituted provide equivalent protection against a fire to the fire protection measure being replaced.

5. Post-LOCA Hydrogen Generation
FSAR Update Appendix 6.2C (LBIE Log No. 97-212)

This change reflects a revised analysis performed by Westinghouse using more representative, yet conservative, assumptions for hydrogen concentration and amounts of aluminum and zinc in the containment. Specifically, the post-LOCA hydrogen concentration was increased from 35 to 60 cc/kg to envelope an anticipated change in procedures to increase the maximum concentration from 40 to 50 cc/kg to account for measurement uncertainty. Also, the allowed aluminum content was reduced from 4,076 to 3,576 lbm and the allowed zinc increased from 44,305 to 48,884 lbm.

Safety Evaluation Summary

Appendix 6.2C of the FSAR Update describes post-LOCA hydrogen generation in the containment. There is a licensing commitment to operate the hydrogen recombiners in such a manner as to keep the hydrogen concentration below 3.5 percent by volume. The revised analysis performed by Westinghouse demonstrates that the hydrogen limit continues to be met. Placing this revised analysis in the FSAR Update is within the licensing basis and there is no unreviewed safety question.

6. Timing for Main Feedwater Pump Trip After MSLB
FSAR Update Appendix 6.2C (LBIE Log No. 97-220)

This change clarifies Appendix 6.2C by adding a sentence to the discussion regarding the time available for the main feedwater pump to trip following a main steam line break. The sentence added is, "The analysis uses a feedwater flow curve that indicates feedwater pump trip at 2 to 2.5 seconds, but evaluation in Reference 14 of the total conservatism in the feedwater flow curve shows that up to 5 seconds time to receive the isolation signal is acceptable." Reference 14 is a letter from Westinghouse to PG&E documenting that the analysis in WCAP-13908 bounds an isolation signal time as long as 5 seconds.

Safety Evaluation Summary

The added information is a clarification of an accident analysis assumption statement. The analysis assumption, is not changed or any of the accident results or conclusions. Therefore, no unreviewed safety question is involved.

7. Installation of 3-Hour Rated Fire Damper
FSAR Update Appendix 9.5A (LBIE Log No. 97-127)

The fire hazards analysis for Fire Areas S-7 and TB-12 in Fire Zone 23-C in FSAR Update Appendix 9.5A was revised to reflect the existence of a 3-hour rated fire damper in the heating, ventilation, and air conditioning (HVAC) ductwork connecting these two area. The previous description indicated that the duct was undampered. The 3-hour rated damper was installed in 1983, but the change was not reflected in the FSAR Update.

Safety Evaluation Summary

A safety evaluation was not written for the change at the time because Unit 2 had not yet received its operating license. The existence of the 3-hour barrier in the duct serves to prevent the spread of a fire in one area to another area, and hence serves to reduce the consequences of a fire.

8. Fire Barrier Descriptions
FSAR Update Appendix 9.5A (LBIE Log No. 98-092)

Errors in fire barrier descriptions have been corrected to reflect current plant configurations. No design changes, procedure changes, or calculation changes are associated with this FSAR Update change.

Safety Evaluation Summary

The changes are being made to conform the FSAR Update with the current plant configuration. No new fire hazards are being introduced and no designs,

calculations, or procedures are being revised. The radiological consequences of a fire or accident are not affected and no physical changes to the plant are involved. Based on the evaluation, it is concluded that no unreviewed safety question is involved.

9. Fire Protection - Reactor Coolant Pump (RCP) Lube Oil Collection System
FSAR Update Appendix 9.5C (LBIE Log No. 97-097)

Appendix 9.5C of the FSAR Update was revised to refer to a deviation, rather than an exemption, from the requirements of Appendix R for the reactor coolant pump (RCP) oil collection system. The appendix was also revised to change the oil flashpoint temperature 480°F to 425°F.

Safety Evaluation Summary

The deviation from 10 CFR 50, Appendix R, involves use of a common lube oil collection tank in lieu of dedicated collection tanks for each reactor coolant pump (RCP). Changing the terminology from “exemption” to “deviation” is an administrative change. Reducing the flashpoint temperature to 425°F is evaluated in DCPP fire hazards Appendix R evaluation (FHARE) 115, where it is concluded that the lower flashpoint temperature does not affect the basis for the deviation or the safe shutdown analysis. Therefore, it is concluded that no unreviewed safety question is involved.

10. Fire Protection Program Administration
FSAR Update Appendix 9.5H (LBIE Log No. 97-138)

FSAR Update Appendix 9.5H was revised to update organization and responsibilities descriptions, update the list of procedures, delete operating and surveillance requirements that are verbatim to existing Equipment Control Guidelines (ECGs), and add a list of ECGs that are related to rire protection systems, 10 CFR 50, Appendix R, and ECG bases. This change was made to reflect current DCPP fire protection system controls.

Safety Evaluation Summary

The FSAR Update change was made to reflect current administration of the DCPP fire protection program. There was no effect on plant operation. No accident (fire or design basis accident) or equipment malfunction probabilities or consequences were affected.

11. Tornado Failure Analysis Table
FSAR Update Chapter 3, Table 3.3-3 (LBIE Log No. 97-175)

This FSAR Update change corrected the tornado failure analysis table, which stated that the automatic make-up valves would fail open on a loss of instrument

air resulting from a tornado. The actual system response of the make-up valves is to fail closed on a loss of air.

Safety Evaluation Summary

This evaluation bases its conclusion on the fact that automatic makeup is not required for component cooling water (CCW) to continue operating during a postulated tornado because other system leakage is not required to be postulated during the tornado. The normal position of the make-up valves is closed. If make-up water were desired after a postulated tornado had damaged the instrument air lines, the make-up valve can be manually bypassed to provide make-up.

12. Reactor Coolant System
FSAR Update Chapter 5 (LBIE Log No. 97-016)

FSAR Update Section 5.4.3 was changed from, “The storage racks are then removed from the refueling cavity and stored at convenient locations on the containment operating deck prior to reactor closure removal and refueling cavity flooding” to “The storage racks are then removed from the refueling cavity for maintenance and inspection prior to reactor closure removal and refueling cavity flooding.” This change was made because closure studs are normally stored outside containment during refueling.

Safety Evaluation Summary

The purpose of Section 5.4.3 is to explain that closure studs are protected from exposure to borated refueling cavity water by removing them from the refueling cavity before the cavity is flooded with borated water. Changing the storage location does not increase the chances of exposure to borated refueling cavity water. Floor loading and missiles outside of containment, in general, have already been evaluated.

13. Electrical Power and Emergency Lighting FSAR Discrepancies
FSAR Update Chapters 8 and 9 (LBIE Log No. 97-019)

This is a general revision to the electrical sections of the FSAR Update. The general revision provides clarification of as-built configurations and consistency with existing procedures. There are no physical changes associated with this revision.

Safety Evaluation Summary

There was an inconsistency in the voltage, frequency, diesel generator speed, and nomenclature used to describe the requirements when the diesel generator energizes the bus. These changes do not increase the probability of an

accident, since they have been changed to be consistent with the Technical Specification, design basis, and accident analysis. The remaining items do not increase the probability of an accident because they are changes to systems and components that do not affect the operability of ESF loads or are editorial in nature.

The changes do not adversely change the operation or maintenance of any equipment that could result in the malfunction of any equipment important to safety. The changes do not result in any physical change or procedural change that could result in the malfunction of any equipment important to safety.

14. 12-kV Cable Spreading Room Transite Panels," Pyrocrete Enclosure Doors, and Fire Hazards Analysis
FHARE 17 and 55, FSAR Update Appendix 9.5A (LBIE Log No. 98-005)

Because the original safe shutdown analysis conservatively assumed a loss of offsite power concurrent with a fire, most of the pyrocrete barriers and one plaster barrier were installed in certain fire areas to protect circuits associated with diesel generators and diesel fuel oil pump operation to ensure that an onsite power source was available for safe shutdown. Based on the revised safe shutdown methodology in Calculation M-680, the safe shutdown analysis for the affected fire areas were reviewed to determine if the fire barrier will still need to protect emergency diesel generator and/or diesel fuel oil pump circuits. As a result of the review, it was determined that offsite power would be available for shutdown in the event of a fire in the affected areas. As a result of not crediting the pyrocrete barriers, two fire hazards Appendix R evaluations (FHAREs) associated with pyrocrete enclosures are no longer required. This change was previously discussed with the NRC on September 17, 1997, and it was determined that this change could be evaluated via the safety evaluation process and would not require prior NRC approval for changing the assumptions related to offsite power.

Safety Evaluation Summary

The changes made to the FSAR Update and revisions to FHAREs reflect the results of the safe shutdown analysis. These changes incorporate the corrective actions completed for NCR N0001887. Not crediting the fire-rated enclosures in some fire areas complies with the requirements of Appendix R, Section III.G. for separation of circuits. These changes will not increase fire hazards, ignition sources, or operation of fire protection equipment and safety-related equipment. Based upon the above criteria and justification, an unreviewed safety question is not involved. Also a change to the DCPP Technical Specifications is not involved.

15. System Performance Evaluation
FSAR Update Section 6.2.3.3.5 (LBIE Log No. 97-122)

The changes made are removing an incorrect reference and corrections to text in Section 6.2.3.3.5 that describes values used to determine the unsprayed volume of “approximately 17 percent” inside containment. Although the value of the unsprayed volume has not changed, the input parameters used to determine the unsprayed volume have been corrected to account for occupied volume above the deck, credit for sprayed refueling cavity volume, and mixing above the spray ring headers. This is a document change only, there is no physical change to the plant and no affect on procedures, plant operations, or accident analysis

Safety Evaluation Summary

This change is to the method of establishing one of the parameters used to evaluate the performance of a safety system to mitigate an accident. The corrections to the input parameters did not change the value of the unsprayed volume, and therefore the analysis of the iodine removal capability of the containment spray is unaffected. So the consequences of accidents remain unchanged.

16. Electrical Bus Configuration During Modes 5 and 6
FSAR Update FSAR Update Chapter 8, Section 8.3.1 (LBIE Log No. 97-176)

This section describes allowed 4-kV, 120-Vac and 125-Vdc bus configurations during Modes 5 and 6. The revision was to clarify the allowed configurations.

This change has been superseded by another change and its evaluation.

Safety Evaluation Summary

The proposed revision clarifies configurations allowed by existing procedures. As noted, this change has been superseded.

17. Low-Pressure Turbine Exhaust Hood Spray Operation
FSAR Update Section 10.2.1.3 (LBIE Log No. 97-161)

The operation description in the FSAR Update for low-pressure exhaust hood spray was changed to better reflect the recommendations and parameters included in the vendor manual, for proper spray operation during plant operation.

Safety Evaluation Summary

This change was performed for clarification, because the description and parameters included in the annunciator response procedure for the operation and parameters of the low pressure turbine exhaust spray did not match the description and parameters contained in the FSAR Update.

This change did not create or increase the frequency of an accident different from those previously evaluated in the FSAR Update. This system is not addressed in the Technical Specifications nor Equipment Control Guidelines. This system does not affect or have inputs to or from any safety related system, systems important to safety, or any protection system for the turbine and reactor.

18. Clarification of the Leak Rate Requirements for Main Steam System Isolation Valves
FSAR Update Section 10.3 (LBIE Log No. 97-064)

Local leak rate testing of valves that isolate main steam system containment penetrations is not required by 10 CFR 50, Appendix J, Section II.H, or by FSAR Update Table 6.2-39, “Containment Piping Penetrations and Valving.” However, some wording in FSAR Update Section 10.3 could have been interpreted to imply that such testing is performed. This wording was revised to remove that potential for misinterpretation and make it clear that such testing is not required.

Safety Evaluation Summary

Such testing is not needed because the main steam system inside containment is a seismically analyzed closed system whose pressure boundary integrity is verified during the containment integrated leak rate test and is not damaged during a loss-of-coolant accident (LOCA), so that post-LOCA containment atmosphere cannot enter that system and escape from the containment via that system's penetrations. Following a steam generator tube rupture accident, the contribution to offsite doses through the subject leakage paths is negligible compared to that through the stuck open 10 percent atmospheric steam dump valve assumed in the FSAR Update accident analysis, and hence need not be considered to be a contributor to offsite dose for this accident. Since leakage through these flow paths is not a contributor to offsite dose, there is no effect on the consequences of an accident as a result of not local leak rate testing them, as allowed by 10 CFR 50, Appendix J, and FSAR Update Table 6.2-39.

19. Increase Steam Generator Blowdown
FSAR Update Section 10.4.8 (LBIE Log No. 97-218)

An engineering evaluation shows that the blowdown to the steam generator blowdown tank (SGBD) can be increased during plant startup and other plant evolutions. The system is designed for 150 gpm continuous blowdown, but can be increased to 320 gpm during plant startups following plant shutdowns in excess of 72 hours.

Safety Evaluation Summary

The SGBD sysem components have been shown by calculation to be able to accommodate the increased blowdown flow. As SGBD piping is 6 inches or smaller, pipe breaks are in the category of minor secondary system pipe breaks. Even with the increased flow, the consequences of pipe failures are bounded by high-energy line breaks associated with either main steam or main feedwater line ruptures. The flow increase has also been shown to be acceptable from an erosion/corrosion standpoint. Therefore, it is concluded that the change does not involve an unreviewed safety question.

20. Gaseous Radwaste System Parameter Change
FSAR Update Section 11.3 and Table 11.3-1 (LBIE Log No. 96-024)

This FSAR Update revision made minor changes to the design and operating parameters of the gaseous radwaste system components described in the referenced table.

Safety Evaluation Summary

This change has no safety impact because there is no change to the equipment and these values were not used in any analysis or licensing basis. The gaseous radwaste system equipment involved with this change is not involved with the gaseous sadwaste accident analyzed in FSAR Update Chapter 15.

21. Mobile Radwaste Processing System
FSAR Update Section 11.5.4.4 (LBIE Log No. 98-074)

This change corrects the FSAR Update by eliminating reference to interlocks and control signals for the mobile radwaste processing system (MRPS), features that the MRPS does not have.

Safety Evaluation Summary

The MRPS is manually operated in accordance with procedures to prevent overflow and spills. Any spill would be contained in the bermed pad and sump for return to the radwaste system. Radwaste overflow accidents are not evaluated in the FSAR Update and there is no need for interlocks and automatic control signals. Therefore it is concluded that this change does not involve an unreviewed safety question.

22. Additional Operations Directors
FSAR Update Section 13.1.2.2.2.1 (LBIE Log No. 98-016)

The change involves appointment of an additional Operations director for periods of high workload.

Safety Evaluation Summary

Appointment of an additional director is an administrative change that does not affect the accidents evaluated in the FSAR Update. Therefore, it is concluded that this change does not involve an unreviewed safety question.

23. Technical Specifications and Equipment Control Guidelines
FSAR Update Section 16.1 (LBIE Log No. 97-101)

In letter DCL-95-222, dated October 4, 1995, PG&E submitted License Amendment Request (LAR) 97-07 that proposed to relocate several Technical Specifications (TSs) to Equipment Control Guidelines (ECGs) and to reference the ECGs in the FSAR Update. During review of LAR 97-05, the NRC staff requested PG&E to add the following wording to FSAR Update Section 16.1:

"ECGs containing relocated TSs are incorporated into the FSAR Update, by reference, in Table 16.1-1.

"For ECGs listed in Table 16.1-1, if the equipment cannot be returned to service as required by the ECG, then a review in accordance with 10 CFR 50.59 is required."

Safety Evaluation Summary

These changes place increased administrative controls on ECGs that are relocated from TSs, but do not change the ECG requirements themselves.

24. Equipment Control Guidelines
FSAR Update Section 16.1 (LBIE Log No. 98-061)

Nine Technical Specifications have been relocated to Equipment Control Guidelines (ECGs) and added to FSAR Update Table 16.1-1 pursuant to License Amendments 120 and 118 dated February 3, 1998.

Safety Evaluation Summary

Adding the nine ECGs to FSAR Update Table 16.1-1 is an administrative change that has no safety or licensing basis implications. Therefore, it is concluded that no unreviewed safety question is involved.

25. Delete Precipitation Gauge Tipping Bucket Accuracy
(LBIE Log No. 97-017)
FSAR Update Section 2.3.3.4 (LBIE Log No. 98-061)

FSAR Update Section 2.3.3.4 specified the accuracy of the precipitation guage tipping bucket. This accuracy specification is excessive detail and is not consistent with other FSAR Update sections. Design Change Package (DCP) J-49101 installed a new tipping bucket with similar but different accuracy specification. This FSAR Update change deletes all reference to tipping bucket accuracy.

Safety Evaluation Summary

Accuracy of the precipitation gauge tipping bucket does not increase the probability of occurrence of accidents. The tipping bucket accuracy is not used in modeling of any accident evaluated in the FSAR Update. The Emergency Plan is not affected by the tipping bucket accuracy. The accuracy specification in the FSAR Update does not affect other equipment important to safety. The accuracy of the tipping bucket is not used in calculating the margin of safety for any technical specification.

26. Wind and Tornado Loadings
FSAR Update Section 3.3 and Associated Tables (LBIE Log No. 97-096)

This change revises information in Section 3.3 of the FSAR Update concerning safety-related equipment potentially exposed to the effects of a tornado. The changes do not represent any physical changes to the plant or procedures. An evaluation consisting of plant walkdowns and an engineering analysis of the effects of tornado wind and/or tornado missiles was performed. The significant conclusions from this evaluation were incorporated into the FSAR Update.

Safety Evaluation Summary

The engineering evaluation and walkdowns identified safety-related equipment and component vulnerabilities to tornado and missile effects. No circumstances were found that violated the tornado licensing basis. Therefore, there is no unreviewed safety question associated with this change.

27. Wind and Tornado Loadings, (Change No. K-3.3(7))
FSAR Update Section 3.3, Table 3.3-2 (LBIE Log No. 97-073)

This change revises the discussion of the wind and tornado design of the major structures, given in FSAR Update Section 3.3, to address certain problems identified during the preparation of Design Criteria Memorandum (DCM) T-9, "Wind, Tornado, and Tsunami." The majority of the changes either correct typographical errors or are editorial. However, certain changes correct minor discrepancies in the text of the FSAR Update:

The discussion of wind loading on the turbine building in Section 3.3.1.2 was clarified to indicate that loads were developed in accordance with U.S. Navy Design Manual DM-2, not the Uniform Building Code, as was implied by the text.

Corrected a misleading statement in Section 3.3.2.1.1 to indicate that PG&E does not have a commitment to a specific design basis tornado wind speed. This statement was originally added during the preparation of the FSAR Update based on a quote from Supplement 7 to the Safety Evaluation Report, which reflected the NRC's attempt to develop a conservative estimate of the tornado wind speed for DCPP, not the wind speeds used by PG&E.

The discussion of atmospheric pressure drop values in Section 3.3.2.1.1 was expanded to include those applicable to both large and small structures.

The discussion of calculational methods used for the determination of tornado missile forces on structures in Section 3.3.2.2.2 was expanded to include those applicable to both concrete and steel structures.

Safety Evaluation Summary

These changes make the FSAR Update consistent with the information contained in the applicable DCM and the design calculations associated with wind and tornado loading. There are no physical modifications to the structures or any changes in the reported wind and tornado resistance of the structures. Therefore, the level of wind and tornado protection afforded to safety-related equipment is not changed. Hence, the ability to safely shut down the plant in the event of severe winds or tornadoes is not affected.

28. Supplemental Meteorological System
FSAR Update Section 3.3.2 (LBIE Log No. 98-077)

This change was made to describe an upgrade to the supplemental meteorological measurement system. The system was upgraded from a single-phase, non-personal computer (PC) based system to a phased array, PC-based (IBM clone) system.

Safety Evaluation Summary

The previous system had Doppler acoustic sounders installed at three locations. The new system is more accurate, effiicent, and reliable than the old system. It was determined that installing Doppler sounders at two locations would provide information equivalent to the three previous locations. Therefore, it was decided to drop the Los Osos site. As this system is only a backup for accident response assessments and is equivalent to the old system, no unreviewed safety questions exist.

29. Component Cooling Water (CCW) System Surge Tank
FSAR Update Section 3.3.2.3.2.2 (LBIE Log No. 97-068)

This change clarifies the FSAR Update description of the redundant CCW surge tank high level alarms to match actual plant configuration. Contrary to the previous description, there is only one high level alarm on the CCW surge tank.

Safety Evaluation Summary

The installed high level alarm on the surge tank is Class II and utilizes a switch and transmitter that are safety-related for pressure boundary integrity only. The high level alarm has no active safety function and is not required to mitigate an accident or prevent an off site dose release. Therefore redundant high level alarms are not required.

30. Installation of the Component Cooling Water (CCW) Surge Tank Pressurization System
FSAR Update Section 3.3.2.3.2.2 and Table 3.3-3 (LBIE Log No. 97-154)

This change was made to reflect reflect the installation of the component cooling water (CCW) surge tank pressurization system. This change also corrected a statement in the tornado failure analysis table, which incorrectly stated that a maximum of 5000 gal. would spill from the surge tank in the event of tornado damage. The actual volume is 8100 gal. Additionally, this change clarified where the discharged 8100 gal would be directed.

Safety Evaluation Summary

The physical implementation of the CCW surge tank pressurization systems was covered by the evaluations performed for Design Change Packages (DCPs) M-049284 and M-050284. This evaluation concludes that revising the FSAR Update to reflect previously evaluated approved system changes does not result in a unreviewed safety question. This evaluation also concludes that the extra volume of CCW discharged as a result of a tornado can be managed by the inside or outside drainage systems without impairing the safety functions of the CCW system or other systems.

31. Detailed Results of the Tornado Evaluation of Turbine Building
FSAR Update Section 3.3.2.3.2.8 (LBIE Log No. 97-018)

This change updates FSAR Update Section 3.3.2.3.2.8 to reflect the in-situ configuration of the tornado missile barriers in the turbine building for the emergency diesel generator air intakes. Previously the FSAR Update indicated that the original air intake louvers were immediately behind the external missile barriers, while, in reality, these louvers were removed during the installation of the missile barriers in 1975. A similar misstatement in Section 4.3.5.1.5 of Design Criteria Memorandum (DCM) T-9 is also corrected.

Safety Evaluation Summary

This change makes the FSAR Update and DCM consistent with the in-situ configuration. There are no physical modifications to the missile barriers or any changes in the reported wind and tornado resistance of the barriers. Therefore, the level of wind and tornado protection afforded to the safety related diesel generators is not changed. Hence, the ability to safely shut down the plant in the event of tornadoes is not affected.

32. High-Energy Line Break (HELB) Compartment Pressurization Time Response
FSAR Update Section 3.6 Figures (LBIE Log No. 98-098)

Some of the high-energy line break (HELB) compartment pressurization time response figures in FSAR Update Section 3.6 have been revised to correct deficiencies.

Safety Evaluation Summary

The figures being revised document the consequences of non-mechanistic HELBs. The post-HELB compartment pressures and temperatures are decreased for some compartments and increased for others, but do not exceed the environmental qualification values for equipment required to mitigate the HELB. Therefore, it is concluded that the changes do not involve an unreviewed safety question.

33. Design of Containment Structure
FSAR Update Section 3.8 and Associated Figures (LBIE Log No. 96-020)

This change updates FSAR Update Section 3.8.1 and several of the associated figures to reflect the latest analyses of the containment shell and liner plate. Containment pressure and temperature transient curves, element forces, and stresses are revised. In addition, an error in the reference to the code applicable to the design of the liner plate is corrected.

Safety Evaluation Summary

This change makes the FSAR Update consistent with the current loadings and analysis results. There are no physical modifications to the containment structure. All loads and stress levels are still well within the acceptance criteria established in the FSAR Update. Therefore, the level of accident protection provided by the containment structure is not changed. Hence, containment integrity and the ability to safely shutdown the plant in the event of a design basis accident is not affected.

34. Lighting and Communication in Containment Personnel Hatches
FSAR Update Section 3.8.1.1.3.3 (LBIE Log No. 98-068)

This change deletes the word “emergency” from the sentence describing the lighting and communications systems in the containment personnel hatches. The lighting and communications systems in the personnel hatches are “normal” systems operating from external “normal” supplies.

Safety Evaluation Summary

A review of 10 CFR 50, Appendix R, other parts of the FSAR Update, NRC Safety Evaluation Reports, pertinent NRC corespondence, and Occupational Safety and Health Administration requirements revealed no requirements or commitments for emergency lighting and communications in the personnel

hatches. Therefore, the change is within the licensing basis and no unreviewed safety question exists.

35. Mid-Loop Operation and Use of Steam Generator Nozzle Dams
FSAR Update Section 5.1.6.5 (LBIE Log No. 97-215)

A section was added to describe reactor coolant system mid-loop operation and use of steam generator nozzle dams. The addition is based on information contained in Westinghouse Technical Report, "RCS Pressurization Analysis for Diablo Canyon Shutdown Scenarios," dated April 1997.

Safety Evaluation Summary

The safety issue evaluations contained in the LBIE reference documents conclude that mid-loop operation with core decay heat no greater than 15.3 MWt will not have an adverse effect on safe operation at DCPP. Since an operating charging pump or gravity feed of the reactor coolant system from the refueling water storage tank, if required due to loss of station power, can provide sufficient inventory to maintain core cooling, the consequences of a loss of residual heat removal cooling event are considered acceptable from the standpoint of safety to operating personnel and to the general public for both high and low decay heat situations. The material added to the FSAR Update is consistent with NRC requirements and PG&E commitments to the NRC. Therefore, no unreviewed safety question exists.

36. Clarification of Water Systems Used During Refueling
FSAR Update Section 5.5.6.2.2.4 (LBIE Log No. 97-124)

Discussions related to filling the reactor cavity during refueling operations were clarified in the FSAR Update to note that several systems other than the residual heat removal (RHR) system can be used for filling and that the RHR inlet isolation valves are not closed if there is fuel in the core.

Safety Evaluation Summary

The changes made are for clarification purposes only. Uncontrolled boron dilution and dilution during refueling are not affected by this change. Therefore, no unreviewed safety question is involved.

37. Changes of Generic Discussions of Valves to Make Them DCPP Specific
FSAR Update Section 6.2 and Table 6.3-1 (LBIE Log No. 96-013)

The generic discussion of emergency core cooling system (ECCS) and containment isolation valves in FSAR Update Sections 6.2 and 6.3 was not completely accurate for DCPP. Not all these valves are double packed and fitted with stem leakoffs to the equipment drain system. What constitutes a full set of

packing is not defined at DCPP. Nor are packless valves always used where possible. Furthermore, at DCPP these valves are normally purposefully not backseated when opened, to help minimize stresses on the valves imposed by thermal transients. Finally, not all body-to-bonnet valve gaskets are asbestos since use of asbestos in the plant has been curtailed. The discussion of these considerations in the FSAR Update was revised to make it specific to DCPP.

Safety Evaluation Summary

These aspects of valve design and operation are all related to controlling their post-accident radioactive leakoff to be less than that assumed in the DCPP offsite dose analysis. At DCPP, assurance that post-accident radioactive leak rate to the environment would be less than that assumed in the offsite dose analysis is demonstrated by performance of surveillance test procedures that measure such leakage from the subject valves. In this manner, it is confirmed by test that the consequences of an accident would not be increased above that previously evaluated.

38. Insulation for CFCU Motor Leads and Connections
FSAR Update Section 6.2.2.3.3.2 (LBIE Log No. 98-055)

This change revises the FSAR Update with regard to the rating of the insulation for the containment fan cooler unit (CFCU) motor internal leads and terminal box-motor interconnections. The FSAR Update previously stated that the insulation rating met or exceeded the rating of the motor (2300 V). The insulation rating, however, only needs to meet or exceed the rating of the service voltage, which is 460 V. The FSAR Update was therefore changed to reflect this reduced voltage requirement by reference to a Westinghouse evaluation contained in a PG&E environmental qualification (EQ) file.

Safety Evaluation Summary

The CFCU motor internal leads and terminal box-motor interconnections only need to exceed the service conditions of the DCPP 480 V system (460 V +/- 10 percent at the motor terminals per Design Criteria Memorandum (DCM) S-64). The Westinghouse evaluation (WCAP-7829) is a part of EQ file 1H-05 and confirms that the use of 600 V cables are adequate to ensure the ability of the CFCUs to fulfill their post-accident function. Therefore, this change does not involve an unreviewed safety question.

39. Evaluation of Insulation Loss and Recirculation Sump Availability
FSAR Update Section 6.2.3.3.8 (LBIE Log No. 97-164)

The containment recirculation sump debris analysis was inconsistent with statements made in the FSAR Update. Specifically, the FSAR Update stated that all fiberglass insulation debris is assumed to be transported to the sump,

and the sump screen is designed to continue functioning without impeding water flow when it is 95 percent blocked. A new insulation debris methodology was developed, based on NUREG/CR-2791, which assumes less than 100 percent of the insulation debris reaches the sump, and utilizes a better criterion (differential pressure drop across the outer screen) for assessing the impact of sump screen blockage. Other conservative assumptions were made which made the new analysis, on the whole, more conservative than the previous analysis.

Safety Evaluation Summary

The containment recirculation sump debris analysis demonstrates that the screen remains operable with old and new methodologies under the worst-case loss-of-coolant accident conditions when both fiberglass and paint debris are deposited on the sump screen. This analysis shows that the sump screen and debris provide low enough flow resistance to ensure adequate flow to the residual heat removal (RHR) pumps, and to ensure that RHR pump net positive suction head is maintained during recirculation.

40. Changeover from Injection Mode to Recirculation After Loss of Primary Coolant
FSAR Update Section 6.3, Appendix 6.3A, and Associated Tables
(LBIE Log No. 97-024)

The FSAR Update was revised to reflect changed assumptions in residual heat removal pump and containment spray pump flows, and containment pressure during the changeover from injection to recirculation following a loss-of-coolant accident (LOCA). Included is a discussion of the single active failure during the changeover. The changes are due to a more accurate analysis using more conservative assumptions. There were no changes in the configuration of DCPP. These changes affected the time available for operator manual actions.

Safety Evaluation Summary

This safety evaluation defines the acceptance criterion for the evaluation of manual switchover to cold leg recirculation as the refueling water storage tank (RWST) volume margin. As stated in Supplement 9 to the Safety Evaluation Report (SSER), there is an implied margin of 32,500 gallons remaining in the RWST at the completion of the switchover to cold leg recirculation. Other design bases for switchover include maintaining sufficient net positive suction head (NPSH) for the emergency core cooling systems (ECCS) and completion of operator switchover actions in about 10 minutes.

The manner in which the ECCS and containment spray system are operated and sequenced during the changeover from the injection mode to the recirculation mode does not change the probability or consequences of any accident previously evaluated in the FSAR Update. Although the new analysis increased the flow rates for the residual heat removal (RHR) and containment spray (CS)

pumps, NPSH is not affected and the total time available for operator switchover continues to be greater than 10 minutes. The analysis shows that there are no increases in probability or consequences of a malfunction of equipment because there is no loss of NPSH which could interrupt continuous cooling flow to the core.

The revised analysis assumptions do not introduce a possible new malfunction of equipment because the flows remain within pump, piping, and instrument design bases. The changes do not introduce any new common mode failures. The safety evaluation specifically includes the analysis of a single failure of an RHR pump to trip automatically. The single failure had not been previously defined nor evaluated. The new switchover time available is still greater than the actual time to accomplish switchover, even under the worst case single failure assumption.

The margin of safety, as defined in the ECCS Technical Specifications (TS) Bases, 10 CFR 50.46, and 10 CFR 50, Appendix K, is not reduced. The available RWST inventory meets the safety analysis and the TS, even with the new, more accurate, instrument uncertainties. The RWST volume margin remaining at the completion of switchover is 37,450 gallons and is greater than the SSER 9 implied margin. Therefore, the margin of safety has not been reduced.

41. Pump Net Positive Suction Head
FSAR Update Section 6.3.2.14 and Table 6.3-11 (LBIE Log No. 96-017)

Revise FSAR Update Section 6.3.2.14 and Table 6.3-11 to capture the minimum sump water elevation static head above the sump flow elevation, as allowed by Regulatory Guide (RG) 1.1, and to increase the residual heat removal (RHR) pump maximum flow rate from 4,500 gpm to 4,900 gpm for the worst case assumption in the post loss-of-coolant accident (LOCA) alignment.

Safety Evaluation Summary

To increase RHR pump maximum flow rate from 4,500 gpm to 4,900 gpm, the required net positive suction head (NPSH) has been increased from 19.5 feet to 25 feet. By taking credit for the minimum water level above the sump floor, the available NPSH is 28 feet which is more than the required NPSHR of 25 feet. Increased RHR pump flow will not impact the post-LOCA emergency core cooling system (ECCS) performance because: (1) there will be more flow to the core to provide cooling, thus increasing conservatism, (2) it will not boost centrifugal charging pumps (CCPs) nor safety injection pumps (SIPs) beyond their runout limits since the boosted pressure from the RHR pump decreases as flow increases, (3) RHR pumps have been actually tested by the vendor to a flow beyond the 4,900 gpm limit, (4) the increased brake horsepower is within the

motor capability, and (5) NPSH margin exists. Therefore, it is acceptable to increase the RHR pump maximum flow rate from 4,500 gpm to 4,900 gpm.

42. Chemistry Environment for Environmental Qualification
FSAR Update Section 6.3.2.4 (LBIE Log No. 98-100)

This change removes the detailed description of the chemistry environment used for environmental qualification in Section 6.3.2.4 and references Section 3.11, where the environmental program is described with references to pertinent documents that contain the details of the chemistry environment used in the testing.

Safety Evaluation Summary

This FSAR Update revision only changes the location of the information about the chemistry of the spray solution used for environmental testing. Therefore, no unreviewed safety question is involved.

43. Digital Feedwater Control System Steam Flow Arbitrator
FSAR Update Section 7.2.2.3.5 (LBIE Log No. 98-048)

This change adds a description of the digital feedwater control system (DFWCS) steam flow arbitrator signal validation function to FSAR Update Section 7.2.2.3.5 based on a Westinghouse safety evaluation. The change shows how the DFWCS meets IEEE Standard 279.

Safety Evaluation Summary

The FSAR Update only discussed the median signal selector function of the DFWCS. The steam flow arbitration function is design basis information that should have been included in the FSAR Update when the DFWCS design change was made. Based on the Westinghouse evaluation contained in NSAL 96-04, the addition of this information was determined to not involve an unreviewed safety question.

44. Addition of Automatic Start on Degraded 4.16-kV Vital Bus Voltage
FSAR Update Section 7.4.1.2.3 (LBIE Log No. 97-153)

The FSAR Update description of automatic diesel generator (DG) start was corrected to add automatic start on degraded 4.16-kV vital bus voltage as well as on loss of offsite power, loss of 4.16-kV vital bus voltage and safety injection (SI). In addition, the description of manual DG controls was corrected to remove the incorrect statement that manual controls for DG starting and control were provided at the vital switchgear. No such controls are located on the 4.16-kV vital switchgear.

Safety Evaluation Summary

The FSAR Update change was made to correct information in the FSAR Update so that the system design and operation were correctly described. No changes were made to the facility or system operation. There was no impact on any accident or equipment analysis evaluation.

45. Discrepancy Between FSAR Update and Calculation IH-100 Rev 10/Plant Information Management System (PIMS) CDB
FSAR Update Section 7.5 and Table 7.5-6 (LBIE Log No. 97-091)

FSAR Update Section 7.5 and Table 7.5-6 contained incorrect instrument ranges for the containment recirculation sump water level (narrow range) and Containment Pressure (wide range). This evaluation addressed changing the range for the narrow range containment sump water level from “88.5 to 97 ft” to “88.5 to 96.6 ft” and changing the range for the wide range containment pressure from “0 to 200 psig” to “-5 to 200 psig.”

Safety Evaluation Summary

The range for the narrow range containment recirculation sump level was changed from “88.5 to 97 ft” to “88.5 to 96.6 ft.” This range should have been changed to “88.5 to 96.6 ft” as part of Design Change Package (DCP) J-41715, which identified the need to change the range statements in the FSAR Update. However, in revising the FSAR Update, the range was rounded from 96.6 ft. to 97 ft.

The range for the wide range containment pressure was changed from “0 to 200 psig” to “-5 to 200 psig.” This range change is in accordance with the original license commitment (see Supplement 14 to the Safety Evaluation Report) to have continuous indication of containment pressure over a range of -5 psig to three times the design pressure of containment for concrete or four times the design pressure for steel. The installed equipment has a range of -5 to 200 psig as was originally installed. Therefore, the FSAR Update is being revised to reflect the correct design of the wide range containment pressure.

46. Thermal and Hydroelectric Plants Underfrequency Setpoints
FSAR Update Section 8.2.2.2 (LBIE Log No. 98-110)

PG&E has revised the hydroelectric generating plant underfrequency setpoints based on the guidelines of the Western Systems Coordinating Council. A discussion of these guidelines and the broad capability of hydroelectric units to operate during underfrequency events has been added to the FSAR Update.

Safety Evaluation Summary

The purpose of the underfrequency setpoints is to provide security and protection of the interconnected bulk power network by arresting frequency decline during periods of insufficient generation. PG&E's load shedding program is intended to automatically shed about 50 percent of the load within its control area. The previously hydroelectric underfrequency setpoint was designed so that hydroelectric generation would be the last units on the grid to trip on underfrequency. This remains true for the revised setpoints. Therefore, changing the hydroelectric underfrequency setpoint does not affect accidents or equipment malfunctions evaluated in the FSAR Update. Based on these considerations, it was concluded that no unreviewed safety question is involved.

47. Diesel Generator Capability
FSAR Update Section 8.3 (LBIE Log No. 97-082)

This change was made to clarify transient voltage and frequency dip and recovery times during load sequencing to discuss previously established commitments with respect to emergency diesel generator (EDG) performance during load sequencing, to recognize that the KWS relays are not credited for performing a safety function, and to appliy Regulatory Guide (RG) 1.9, Rev. 2, "Regulatory Position C4," as it pertains to voltage and frequency dip and recovery during load sequencing,

Safety Evaluation Summary

DCPP meets the frequency and voltage dip requirements of RG 1.9, Revision 0, as demonstrated by analysis in DCPP Calculation 215-DC, Revision 2, for nominal load block time intervals. DCPP meets the frequency and voltage recovery requirements of RG 1.9, Revision 0, as demonstrated by analysis in Calculation 215-DC, Rev. 2 for nominal load block time intervals. DCPP meets commitments to the NRC in PG&E Letter DCL 85-132 for demonstrating that the objectives of RG 1.9 are met for worst case load block time intervals, as demonstrated by analysis in Calculation 215-DC, Revision 2, and preoperational testing.

48. Diesel Generator Frequency Dip and Recovery
FSAR Update Section 8.3.1 (LBIE Log No. 98-034)

FSAR Update Section 8.3.1.1.13, "Diesel Generator Units," has been revised to clarify transient voltage and frequency decrease and recovery times during load sequencing. Specifically, the revisions (1) apply the criteria of Regulatory Guide (RG) 1.9, Revision 2, "Regulatory Position C4," as it pertains to voltage and frequency dip and recovery during load sequencing, (2) documents previously established commitments to demonstrate emergency diesel generator (EDG) performance during load sequencing with worst-case sequence timing intervals,

and (3) explicitly states that the KWS relays are not credited for performing a safety function.

Safety Evaluation Summary

The evaluation performed shows that the EDGs (1) meet the frequency and voltage decrease requirements of RG 1.9, Revision 0, for nominal load block time intervals, (2) meet the frequency and voltage recovery requirements of RG 1.9, Revision 2, for nominal load block time intervals, and (3) meet commitments to the NRC for demonstrating that the objectives of RG 1.9 are met for worst-case load block time intervals. Additionally, analysis is referenced that demonstrates acceptable frequency recovery without crediting the KWS relays. Based on the results of the evaluation, it is concluded that no unreviewed safety question is involved.

49. Diesel Generator Starting Air Requirements
FSAR Update Section 8.3.1.1.13.2 (LBIE Log No. 97-053)

FSAR Update Section 8.3.1.1.13.2 is revised to clarify the statement “three (3) consecutive 15-second cranking cycles” as it relates to nominal sizing criteria for the air start receivers. This FSAR Update change revises the text to identify the “three (3) consecutive 15 second cranking cycles” as sizing criteria used by the vendor to size the air start receivers .

Safety Evaluation Summary

The emergency diesel generators (EDGs)) are not accident initiators. This change is not the result of any physical modification to the EDGs or related systems. The capability of the DEGs to perform their design function will not be adversely impacted by revision to the FSAR Update text to clarify the starting air receiver sizing criteria. The probability of occurrence of an accident, malfunction of equipment important to safety, radiological consequences of accidents evaluated, different type of accidents, or margin of safety previously evaluated in the FSAR Update will not be adversely impacted. Therefore, revising the FSAR Update text to clarify the EDG starting air receiver sizing criteria will not result in an unreviewed safety question.

50. FSAR Update Change Chapter 8.3.1.1.13.6
FSAR Update Section 8.3.1.1.13.6 (LBIE Log No. 97-162)

This section describes diesel generator engine trips. The change deletes the 4160-V bus differential from the list of trips.

Safety Evaluation Summary

The proposed revision modifies an existing section of the FSAR Update to correct an error. The 4160-V bus differential only trips the 4-kV breaker to the diesel generator. It does not trip the diesel generator. There is no safety significance to this change since there is already a failure that would disable the diesel from providing power to its load. The correction describes the as-built response to this failure.

51. Modes 5 and 6 Electrical Alignment
FSAR Update Section 8.3.1.4 (LBIE Log No. 97-057)

The change addressed the removal from FSAR Update Section 8.3.1.4, Independence of Redundant Systems [Class 1E Electrical Systems], of material describing contingency configurations for Mode 5 and 6 operation. This material was not incorrect, but it was an inappropriate level of detail, and it described sample configurations that may not be utilized.

Safety Evaluation Summary

There was no identified safety impact of removing the material. The described configurations are still allowed.

52. Deletion of Requirement for Cables Terminating on Separate Terminal Blocks
FSAR Update Section 8.3.1.4 (LBIE Log No. 98-003)

This FSAR Update change deletes the requirement that redundant cables terminate on separate terminal blocks. It properly characterizes that they "typically" are terminated on separate terminal bolts.

Safety Evaluation Summary

The design basis is that mutually redundant circuits be separated by 5 inches or a separation barrier. When mutually redundant circuits are terminated on the same terminal block, barriers are an acceptable means of providing separation and are provided up to the terminal block as required by Design Change Memorandum (DCM) T-19. The terminal block provides sufficient clearance and leakage distance to meet the requirements of a separation barrier. The barriers assure that the probability or consequence of an accident will not be increased.

53. Use of ICEA P-54-440 for Derating of Cable Installed in Cable Tray
FSAR Update Section 8.3.1.4.3 (LBIE Log No. 96-029)

The FSAR Update has been updated to reflect the use of Standard ICEA P-54-440, which is the industry recognized method for derating cables installed within cable tray. ICEA P-54-440 derates cable ampacity based upon percent fill.

Safety Evaluation Summary

Cable ampacity is not the source of an accident and does not impact the consequences of a malfunction of equipment. Cable derating is not related to creation of accidents or to the margin of safety. The probability of occurrence of a malfunction of equipment or the possibility of a malfunction of equipment important to safety will be decreased by the use of standard ICEA P-54-440.

54. Reactor Vessel Stud Detensioning
FSAR Update Section 9.1.4.2.1.13 (LBIE Log No. 98-014)

The FSAR Update is revised to eliminate reference to the number of reactor vessel stud tensioners required for tensioning and detensioning activities.

Safety Evaluation Summary

An engineering evaluation of reactor vessel stud tensioning and detensioning procedures has been performed and revised procedural guidance developed and implemented. As part of the revised procedure, detensioning may be accomplished with either six or three hydraulic tensioners, or with only two if one fails. The revised procedure has no effect on accidents analyzed in the FSAR Update. All ASME Code stress and fatigue limits will be met and there will be no effect on any other safety-related equipment. Therefore, it is concluded that the proposed change does not involve an unreviewed safety question.

55. Auxiliary Systems/Fuel Storage and Handling
FSAR Update Section 9.1.4.2.1.4 (LBIE Log No. 97-155)

The FSAR Update section was revised to remove a statement that the fuel handling building (FHB) crane is normally stored in the hot shop. The statement was not supported by any commitment or basis. The FHB crane is seismically qualified for its entire runway. Parking is not restricted. Removing the statement from the FSAR Update eliminated unnecessary movement of the FHB moveable seal walls, and allowed operations flexibility to store the crane to better support normal operations.

Safety Evaluation Summary

The only FHB crane accident evaluated in the FSAR Update is a load drop over irradiated fuel. The crane is seismically qualified for its entire runway. Travel over the spent fuel pool (SFP) is controlled by Technical Specification 3/4.9.7 and by plant procedures. The crane is not stored over the SFP. No new accidents are created by storing the crane in the FHB while not in use. Allowing the crane to remain in the FHB while not in use will not affect any accident analysis. Equipment required for safe shutdown is not affected because crane storage is limited to FHB areas that do not contain equipment important to safety.

56. Relief Valve Criteria
FSAR Update Section 9.2.2.2.9 (LBIE Log No. 97-052)

The change addressed was the removal from FSAR Update Section 9.2.2.2.9, component cooling water (CCW) system valves, of the paragraph which contains the following information: "The relief valve [RV-52] on the component cooling water piping downstream of the excess letdown heat exchanger is sized for a tube break in the heat exchanger …. The relief capacity of this valve is such that the design pressure of this portion of the CCWS will not be exceeded."

Existing DCPP calculation for this valve demonstrating capacity is an equilibrium calculation. Equilibrium assumptions like perfect mixing are not as conservative as a three-dimensional transient analysis would be. It would be difficult to perform an accurate two-phase, three-dimensional analysis, and it is believed that the results may indicate higher than design pressures.

Safety Evaluation Summary

The justification for removing the statement is that there is no need to design against a tube rupture in this heat exchanger. A tube rupture here is a non-credible event. These tube walls are relatively thick, the fracture analysis indicates that failures will be more likely to be axial cracks and double-ended rupture will not occur, and inservice time for these heat exchangers (HXs) is very low (typically these HXs are only used when mechanical troubles exist in the normal letdown HX path. Westinghouse discusses the non-credibility of a tube break in letter PGE-97-530. Not assuming a double ended rupture in these 5/8-in. tubes is consistent with NRC Standard Review Plan 3.6.1, Appendix B, which does not require assuming circumferential breaks in pipes of less than 1-in. diameter.

DCPP's excess letdown heat exchanger is similar to most Westinghouse designs and no other Westinghouse FSAR Update has been discovered with this design statement. It does not appear in RESAR-3 or the updated FSARs of Turkey Point, Vogtle, Shearon Harris, Salem, Sequoia, or Commanche Peak.

Therefore, removal of this statement makes the DCPP FSAR Update consistent with sister Westinghouse plants, and enables PG&E to avoid reliance on a calculation believed to be non-conservative.

Licensing material such as the Standard Review Plan and (Supplement to Safety Evaluation Reports (SSERs) were reviewed. There was no evidence discovered that would lead to the conclusion that the NRC relied upon this function of RV-52 to grant the DCPP Operating License.

57. Delete Reference to Flow Switch 22
FSAR Update Section 9.2.3.3 (LBIE Log No. 97-114)

All references to flow switches/alarms (FS-22) are deleted from Section 9.2.3.3. FS-22 is located in the main makeup water header from the raw water reservoirs into the fuel handling building/auxiliary building. It has been concluded that break flow would not be enough to actuate the FS-22. No fieldwork is planned - the switches are to remain installed but not maintained.

Safety Evaluation Summary

The probability of occurrence of an accident (flooding) does not increase by deleting the flow switches/alarms in Section 9.2.3.3. The auxiliary building sump's high level alarm is adequate to detect and mitigate flooding, therefore break detection and isolation can still be accomplished as before.

58. Liquid Sampling System FSAR Update Discrepancies
FSAR Update Section 9.3 and Table 9.3-2 (LBIE Log No. 97-072)

These changes are made to revise sample transit time, make an editorial change in the description of sample flow, and revise the number of sample heat exchanger and sample heat exchanger design information.

Safety Evaluation Summary

There is no safety impact because this change does not involve any physical change to the plant. The changes are being made to update the design data in the FSAR Update and to better reflect actual plant conditions. Therefore, there is no increase in probability or consequences of an accident and no reduction in margin of safety.

59. Testing of Floor and Equipment Drainage Systems
FSAR Update Section 9.3.3.4 (LBIE Log No. 98-099)

This change clarifies the monitoring and testing performed on the floor and equipment drainage system prior to and during plant operation. It states that the systems were tested and inspected prior to plant operation and are periodically monitored during plant operation.

Safety Evaluation Summary

The evaluation performed for this clarification concluded that no unreviewed safety question is involved.

60. Undampered Ventilation Duct Penetrations
FSAR Update Section 9.5.1 and Appendices 9.5A and 9.5B
(LBIE Log No. 97-139)

DCPP fire hazards Appendix R evaluation (FHARE) 33 evaluates the acceptability of having ventilation duct penetrations that do not have fire dampers and do meet the 3-hour rating definition for a fire barrier. Some of the undampered duct penetrations have been previously described to the NRC in the Unit 2 10 CFR 50, Appendix R, report. See Supplement 31 to the Safety Evaluation Report for approval of deviations.

FHARE 33 was revised to incorporate the current safe shutdown analysis (DCPP Calculation M-928) and to delete a ventilation duct penetration previously evaluated as undampered but where a fire damper was actually installed. With the addition of the sixth diesel generator (DG 2-3), the physical layout of the plant was changed along with the safe shutdown analysis due to new safe shutdown circuits. A new layout and fire area was added for DG 2-3. References and combustible loading description were revised to be consistent with the FSAR Update and the combustible loading calculation.

Safety Evaluation Summary

FHARE 33 evaluates an as-built condition against the effects of a postulated fire. No new fire hazards were introduced. Normal function of safety-related equipment was not affected. Fire protection features were not changed. Probability of a fire or of other accidents was not changed. The primary changes to FHARE 33 involved addition of a new fire area for the DG 2-3 room and incorporation of the safe shutdown analysis in Cal. M-928. The changes do not affect ability to achieve and maintain safe shutdown. FHARE 33 does not affect non-fire accidents evaluated in the FSAR Update.

61. Computer-Based Fire Alarm System
FSAR Update Section 9.5B (LBIE Log No. 98-029)

In response to NRC Open Item 275/87-27-02, DCPP committed to install a computer based fire alarm system capable of providing the features specified in National Fire Protection Association (NFPA) 72D. This new fire alarm system has back up power through an uninterruptible power supply or batteries that meets the requirements of NFPA 72D. As a result of this change, FSAR Update Section 9.5B is revised to clarify the sources of back up power for the fire detection and alarm panels

Safety Evaluation Summary

This change only clarifies the sources of back up power for the fire detection and alarm panels. There is no increased probability of an accident, no increased accident consequences, no increase in the probability of occurrence of malfunction of equipment and no increase in consequences due to equipment malfunction. No new type of accident is created and there is no reduction in the margin of safety as defined in the Technical Specifications.

62. Drainage to the Equipment Drain Tank and Auxiliary Building Sump
FSAR Update Sections 11.2.2.2 and 11.2.2.3 (LBIE Log No. 98-075)

This change corrects drainage inputs from equipment in the auxiliary building that are collected in the miscellaneous equipment drain tank and corrects sources of potentially contaminated auxiliary building floor drain wastes that are collected in the auxiliary building sump.

Safety Evaluation Summary

The changes to the FSAR Update involve the specific routing of wastes to closed and open drains to bring the document into conformance with the plant design. The total amount or processing of liquid waste is unaffected. None of the changes decrease confinement and most increase confinement. Potential accidents analyzed in the FSAR Update are unaffected. Therefore, it is concluded that no unreviewed safety question is involved.

63. General Reference to the DCPP Q-List
FSAR Update Sections 3.1 and 3.2 (LBIE Log No. 96-019)

The substance of these changes represents an enhancement of the presentation of the design bases and classification details for DCPP structures, systems, and components (SSCs). No physical or de facto changes were made to the plant; no analyses or analysis assumptions or inputs were revised; no SSC classifications were changed; DCPP compliance with the general design criteria (GDC) remains unchanged; control of the DCPP design basis is maintained.

Safety Evaluation Summary

Previously-evaluated accidents and malfunctions probabilities and dose consequences are unaffected, no new or different types of such events are created or become credible, and no interface with the technical specifications or their bases results from these changes.

64. Factors of Safety for Structure Gaps and Raceway Flexibility
FSAR Update Sections 3.8.1.5.3 and 3.10.2.18 and Table 3.8-5B (LBIE Log No. 98-108)

The FSAR Update changes evaluated are necessary to account for the dimensions of existing gaps between interior and exterior surfaces of the containment structure determined during walkdowns. The specific changes involve revision of the FSAR Update to account for revised factor of safety calculations that consider relative seismic displacements. Also, the FSAR Update section on electric cable raceways is revised to show that the effects of differential displacements on raceways spanning between structures can be accommodated through either use of flexible joints or through the flexibility of the raceway and its supports.

Safety Evaluation Summary

The existing gaps in the containment annulus and between the containment structure and the auxiliary building have been compared with calculated seismic displacements at several elevations. Factors of safety against contact have been determined and found to be adequate. Evaluations have also been performed to ensure that electric raceways between structures can withstand structural shifts due to seismic effects without damage. Based on a detailed consideration of each of the 10 CFR 50.59 questions, it has been determined that the seismic gap issues do not involve an unreviewed safety question.

65. Reactor Coolant System FSAR Update Discrepancies
FSAR Update Sections 5.1, 5.2, 5.4, and 5.5 (LBIE Log No. 97-069)

The changes are made to clarify the content of the FSAR Update and better describe the system design and operation. Also, changes are made to correctly describe the actual inspection performed. No physical changes are being made to the plant due to this FSAR Update change. The changes are made to more precisely describe system and the inspection of various components. No commitment or required inspection is being removed.

Safety Evaluation Summary

There is no increase in probability or consequence of an accident and no reduction in margin of safety. Therefore, it is concluded that no unreviewed safety question is involved.

66. Residual Heat Removal System FSAR Update Discrepancies
FSAR Update Sections 5.2, 5.5, 5.6, Tables 5.2-10 and 5.2-22 (LBIE Log No. 97-070)

The changes are made to precisely describe the content of the FSAR Update, to reflect the actual setpoint of the low-pressure alarm (pressurizer relief valve interlock), and to remove some unnecessary information to reflect the as-installed condition.

Safety Evaluation Summary

No safety impact exists because this FSAR Update change notice does not involve any physical change to the plant. The changes are being made to more precisely describe system and the inspection of various component. No commitment or safety function of the affected equipment is being changed. Therefore, there is no increase in probability or consequences of an accident or any reduction in margin of safety.

67. Reactor Vessel Fluence Calculations
FSAR Update Sections 5.2.4.4.4 and 5.2.4.4.5 (LBIE Log No. 97-177)

FSAR Update Sections 5.2.4.4.4 and 5.2.4.4.5 are revised to reflect the current methodology used by industry for performing reactor vessel fluence calculations. The methodology change incorporates more modern and accurate methods, new neutron transport computer programs and cross section database, has been reviewed and approved by NRC (WCAP -14040-NP-A), and is consistent with Draft Regulatory Guide DG-1025, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.”

Safety Evaluation Summary

This change to the methodology for calculating reactor vessel fluence has been benchmarked, and reviewed and approved by NRC (WCAP-14040-NP-A). While the updated fluence methodology could affect calculation of reactor pressure vessel (RPV) fracture toughness, inadequate fracture toughness leading to a postulated failure of the RPV is outside the plant design basis. Fracture toughness requirements are ensured through the federal regulations (10 CFR 50.60, 10 CFR 50.61, and 10 CFR 50, Appendix G, in combination with monitoring programs required by 10 CFR 50, Appendix H). This change in fluence methodology has no impact on the existing fracture toughness limits, or

the margin prescribed to these limits (which account for uncertainties in vessel fluence measurements and methodology), or the methods for calculating RPV fracture toughness (ASME B&PV Code Sections III and XI, Appendix G, and 10 CFR 50, Appendix G).

68. Reactor Coolant System FSAR Update Discrepancies
FSAR Update Sections 5.5, 5.6, Tables 5.2-9, 5.2-16, and 5.5-16 (LBIE Log No. 97-071)

The changes are made to: (1) more precisely describe the reactor coolant system (RCS), (2) delete redundant information, and (3) reflect the actual installed equipment.

Safety Evaluation Summary

No safety impact because this FSAR Update change notice does not involve any physical modification to the plant and the design and/or function of the RCS has not been changed.

69. Valve Leakage Criteria
FSAR Update Sections 6.2 and 6.3, Tables 6.3-1 and 6.3-3 (LBIE Log No. 97-133)

The FSAR Update is updated to clarify that the valve leakage criteria listed in Section 6.2.4.2.2 and Table 6.3-1 are those used for initial valve purchase, and not used for maintenance/in-service testing, and that the specific valves requiring a specific leak rate are covered by Technical Specification required surveillance testing programs.

Table 6.3-3 was updated to reflect that valves may have corrosion resistant bolting in addition to the listed low alloy bolting.

Safety Evaluation Summary

This change to the FSAR Update is a clarification to the text/table which does not affect the operation of the facility. The affected emergency core cooling system (ECCS)/containment isolation valves cannot cause any evaluated accident. The consequences of an accident are not increased as the valves in question perform their safety function unchanged in any manner. All valves in which leakage is a safety requirement remain tested per Technical Specification requirements.

70. Sodium-Hydroxide Additive Tank (SAT) Low-Level Alarm Function
FSAR Update Sections 6.2.3.4.2.1 & 6.2.3.5.3 (LBIE Log No. 98-004)

The change to FSAR Update Section 6.2.3.5.3 is a change to an incorrect description of the function of the SAT low-level alarm described in the FSAR Update. The SAT level instrumentation is not safety- related and is set to alarm just above the minimum required Technical Specification level. Operator action is required to investigate the cause of the low level alarm and to increase SAT inventory to within its normal operating band. No operator action is required when the SAT inventory is depleted during a loss-of-coolant accident (LOCA), and therefore no alarm is provided for this function.

Safety Evaluation Summary

The low level alarm provides early warning to operators to ensure that minimum SAT inventory is available pursuant to Technical Specification requirements.

During an accident, when the SAT is depleted, it would have performed its safety function of providing pH control for iodine removal by the containment spray. Under certain LOCA scenarios, it is possible for the SAT to be depleted before emergency core cooling system (ECCS) injection phase is completed (refueling water storage tank (RWST) at low-low level). This would allow nitrogen from the SAT to be ingested into the containment spray system (CSS) pumps near the end of the ECCS injection phase until the CSS pumps are shut off. An evaluation was performed indicating that the amount of nitrogen ingestion does not affect the CSS pumps from performing their containment spray function and transferring the RWST contents into the containment. The CSS pumps are not required for accident mitigation after completion of the injection phase of ECCS and the CSS pumps are shut off.

71. Clarification of Load Rejection Capabilities
FSAR Update Sections 7.7.1.8 and 10.4.4.1 and Table 1.3-1 (LBIE Log No. 97-149)

Prior to this change, the context of the referenced FSAR Update sections stated that the reactor would not trip following a 100 percent load loss. The DCPP turbine bypass system was designed to accommodate a load rejection above 50 percent power without a reactor or turbine trip. However, due to the large number of systems that must operate precisely in a fully coordinated manner, a manual or automatic reactor trip may follow a large load rejection. In fact, there has been only one occasion where a full load rejection has not resulted in a reactor trip.

Safety Evaluation Summary

The FSAR Update change was made to better describe the plant response following a large load rejection event. It was not made because of any plant equipment modification or a change in the way the plant was operated. No new or different accidents or malfunctions were introduced. There was no change

that could affect the cause of a load rejection event. Therefore, the probability of a load rejection event, either with or without a reactor trip, is not affected.

The FSAR Update change clarifies the response of the plant to most load rejection events. The plant was designed to accommodate a full load rejection event without a reactor or turbine trip, and this design was not changed. FSAR Update Section 15.2.7 evaluated full load rejection events both with and without reactor trip. Consequences of a load rejection event are not increased whether or not the reactor trips.

The change implies a potential decrease in load rejection events without reactor trip, and a corresponding increase in load rejection events with reactor trip. Such an increased reactor trip frequency could affect the plant's cyclic or transient design. Technical Specification Table 5.7-1 reactor trip system cyclic limits were not approached or exceeded when the current reactor trip rates were extrapolated for the remaining life of each DCPP unit. There is no effect on probability of an evaluated equipment malfunction.

72. Sale of MBPP and Establishment of the Independent System Operator (ISO)
FSAR Update Sections 8.1, 8.2 and 8.3 (LBIE Log No. 97-191)

Changes to FSAR Update Sections 8.1, 8.2 and 8.3 were made to reflect 230-kV system operation without the Morro Bay Power Plant (MBPP) and the addition of capacitor banks at DCPP. The changes also address the transfer of the 230-kV and 500-kV transmission system control from PG&E to the ISO.

This change also addresses the voltage improvements in the plant buses achieved through the installation of new startup transformers with automatic load tap changing feature. The new startup transformers are designed to maintain a preset voltage at the plant buses regardless of the 230-kV system voltage variations.

Safety Evaluation Summary

DCPP meets the design basis requirements for offsite power availability according to the commitments to 1971 general design criteria (GDC) 17, Regulatory Guides 1.6 and 1.32, and IEEE 308.

The offsite power remains reliable since the ISO is required to operate the grid in a reliable manner and maintain sufficient capacity and voltage to assure that safety loads are operable when powered from offsite power. The ISO has commited to comply with the requirements of Operating Instruction O-23. Operating Instruction O-23 provides minimum 230-kV voltage requirements to maintain DCPP operability with and without shunt capactors and no MBPP generation. This change does not result in a change of operation, maintenance,

physical change, or procedural change that would affect the probability or consequence of an accident.

73. HVAC System Changes
FSAR Update Sections 9.4 and 12.2 (LBIE Log No. 96-012)

Miscellaneous changes were made to the wording of the FSAR Update description and discussion of the DCPP heating, ventilating, and air conditioning (HVAC) systems.

Safety Evaluation Summary

A few of the changes were to more accurately reflect the actual configuration, function, or operation of HVAC systems, but have no affect on, or relation to, the safe operation of the plant or the system's ability to mitigate an accident or the probability of equipment malfunction. The nature of these wording changes to increase the accuracy of the FSAR Update is such that none of them has any effect on the probability of an accident occurring, on the consequences of an accident, on the probability or consequences of equipment malfunction, or on margin of safety.

74. FHB Ventilation Flow and Control Room Heat Load
FSAR Update Sections 9.4.4 and 9.4.5 (LBIE Log No. 98-094)

The changes involve updating the flow quantities of the fuel handling building (FHB) ventilation system and the control room (CR) heat load, as well as numerous editorial corrections.

Safety Evaluation Summary

The FHB ventilation system is designed to help mitigate a fuel handling accident in the FHB. The total as-built exhaust flows are the same for both units, but the branch flows are different. The Chapter 15 accident analysis is based on total flow, so branch flow has no impact on analysis results.

The design heat load for the control room was used to size the air conditioning equipment. Ample margin exists so that changes in calculated heat load, including accident conditions, can be accommodated. In both cases, it is concluded that the updating of FHB ventilation flow and CR heat load do not involve an unreviewed safety question.

75. Clarification of Procedure Enhancement Documentation
FSAR Update Table 17.1-1 (LBIE Log No. 98-027)

A clarification is added to the exceptions related to quality assure program requirements to explain the administrative control used to provide procedure enhancements feedback to the procedure sponsor.

Safety Evaluation Summary

The change deals with clarification of an administrative control regarding tracking of procedural enhancements and has no bearing on accidents evaluated in the FSAR Update. Therefore, it is concluded that no unreviewed safety question is involved.

76. Clarifications to the List of Active Valves
FSAR Update Table 3.9-9, Rev. 11A (LBIE Log No. 97-147)

The list of active valves in FSAR Update Table 3.9-9 contains valves that have a design basis active safety function to support accident mitigation and achieve safe shutdown, and also contains valves that have a nonsafety-related licensing basis active function to support achieving cold shutdown following a Hosgri earthquake. The distinction between these two classifications of valves has been made in other design basis documents outside the FSAR Update, but has not been made in this FSAR Update table. In addition, as iterated in the Diablo Canyon Supplement 7 to the Safety Evaluation Report (SSER) and SSER 22, DCPP is a “hot shutdown” plant, meaning that following an accident, “safe shutdown” is considered to be Mode 3. However, DCPP is required to be capable of achieving cold shutdown following a Hosgri earthquake or 10 CFR 50,Appendix R, fire with no concurrent accident. Again, while this distinction between the design basis safe shutdown and licensing basis shutdown definitions has been made in other design and licensing basis documents, it is not readily apparent in the FSAR Update. To clarify these two distinctions in the FSAR Update, two notes were added to the list of active valves in Table 3.9-9 that explain the distinctions.

Safety Evaluation Summary

While this constitutes a change to the FSAR Update, thus requiring a 50.59 safety evaluation, it is for clarification only, and does not constitute a change to the DCPP design or licensing basis. There is no change in the Code or quality classification, quality assurance, maintenance, or surveillance testing of any of the listed valves resulting from adding this additional clarifying information. The operability, dependability, and behavior of the valves is unchanged, and hence the consequences of an accident are unchanged.

77. CCW Train Separation Valve Designation
FSAR Update Table 3.9-9 (LBIE Log No. 97-063)

The component cooling water (CCW) system is normally operated with its two safety-related trains cross-connected. Since a passive failure of one of the trains is postulated after 24 hours after a loss-of-coolant accident (LOCA) has occurred, the system is designed to allow separation of the trains using manually operated valves. The valves used to accomplish this train separation are considered to be active valves and are listed in the FSAR Update Table 3.9-9 list of active valves. The configuration of the system is such that the trains could be separated in several ways, using different combinations of manual valves. Table 3.9-9 was revised to list the valves actually used by procedure to perform the train separation.

Safety Evaluation Summary

All the valves involved have the same Code classifications and level of maintenance and testing, and are equivalently capable of achieving the train separation. Hence there is no change in the potential consequences of an accident because there is no change in the ability to achieve CCW train separation using the equivalent set of valves indicated in the Emergency Operating Procedure when compared with using the set originally listed in the FSAR Update.

78. Reactor Coolant Pressure Boundary (RCPB) Leakage Detection Systems
FSAR Update Table 5.2-16 (LBIE Log No. 98-089)

This change revises Table 5.2-16 to correct typographical errors, clarify ranges of instruments, restate the way containment condensation liquid detectors respond, and updates the approximate time needed to detect a 1-gpm leak for each detector.

Safety Evaluation Summary

The proposed changes in FSAR Update Table 5.2-16 do not affect the function of the reactor coolant pressure boundary (RCPB) leakage detection systems, do not degrade the ability of the plant to detect a reactor coolant system (RCS) leak, and do not impact any assumptions made in evaluating the radiological consequences of accidents. There is no change in equipment reliability and no impact on fission product barriers. The changes simply bring the FSAR Update into agreement with the plant design licensed by the NRC and therefore do not create the possibility of an unreviewed safety question.

79. Administrative Control of Containment Isolation Valves 8823, 8824, 8843, and 8885A/B
FSAR Update Table 6.2-39 (LBIE Log No. 97-213)

This change updates Table 6.2-39 to show that the administratively controlled Containment Isolation Valves 8823, 8824, 8843, and 8885A/B do not have active

control room position indication while they are administratively cleared, i.e., the control room indicating lights do not function.

Safety Evaluation Summary

The changes are FSAR Update clarifications that do not affect operation of the plant or the results of any accident analyses. Therefore, no unreviewed safety question exists.

80. Post-Accident Monitoring Indicators
FSAR Update Table 7.5-4 (LBIE Log No. 98-088)

This change corrects a typographical error and deletes “indicator” from the plant vent monitor as low as reasonably achievable (ALARA) since only a recorder exists for this variable.

Safety Evaluation Summary

The plant vent monitor ALARA is a Regulatory Guide 1.97, Category 3, variable for which only a recorder is needed. This change is a document change only and involves no physical work The change is within the licensing basis and does not involve an unreviewed safety question.

81. Emergency Diesel Generator (EDG) Stop Button Loads for Battery 13
FSAR Update Table 8.3-11 (LBIE Log No. 98-091)

The power supply to the emergency diesel generator (EDG) emergency stop buttons was deleted and the buttons were wired directly to the shutdown lockout relays. The buttons are therefore no longer a load for Battery 13 and the FSAR Update was revised accordingly.

Safety Evaluation Summary

Modification of the stop button circuit is a design improvement that enhances reliability. The licensing basis is unattended; hence, no unreviewed safety question is involved.

82. Control Room Indicator Accuracy and Range Statements
FSAR Update Tables 7.5-1 Through 7.5-5 (LBIE Log No. 97-038)

There were several instances of inconsistent information concerning control room indication accuracy and range statements in FSAR Update Tables 7.5-1 through 7.5-5 as compared to the design calculations, supporting documents and as-built design. These changes were reviewed by all affected DCPP departments.

Safety Evaluation Summary

Many of the accuracy statements in FSAR Update Tables 7.5-1 to 7.5-5 are more conservative than what has been computed in design and supporting calculations. The proposed changes to the FSAR Update are intended to report the current and the correct status of the plant. The collective coordination related to this FSAR Update change request with the appropriate departments and groups ensures the consideration of control room indication accuracy in the plant activities are consistent with the plant design parameters. Therefore, there is no increase in the probability or consequences and no reduction in margin of safety.

83. Boric Acid Heat Tracing and Tank Heater Loads
FSAR Update Tables 8.3-3, 8.3-5, 8.3-6, and 8.3-7 (LBIE Log No. 97-214)

FSAR Update tables were revised to account for a reduction of electric heat tracing and tank heater loads of the boric acid system. The heater loads were previously assumed to be operating at 100 percent rated capacity. Since the heaters are temperature controlled and operate intermittently, their loading was reduced to 50 percent.

Safety Evaluation Summary

Reducing the heat tracing and tank heater loads of the boric acid system, which is not safety related, makes the FSAR Update consistent with plant operation. The margin of safety is not reduced and it concluded that this change does not involve an unreviewed safety question.

G. Other Changes

1. Reclassification of Containment Spray in the Recirculation Mode of Emergency Core Cooling to Nonsafety-Related
(Units 1 & 2) (LBIE Log No. 97-206)

This evaluation justified the reclassification of the containment spray system to nonsafety-related during the recirculation mode of a loss-of-coolant accident (LOCA), thereby eliminating the requirement that the containment spray system be functional during recirculation.

Safety Evaluation Summary

The safety evaluation concluded that the reclassification is justified since containment spray is only required to be in service during the injection phase of an accident, and not during the recirculation phase of an accident.

Note, however, that during the NRC architect-engineer inspection conducted in August and September 1997, the inspection team indicated that PG&E's decision to declassify the containment spray function during the recirculation phase of a LOCA was a potential unreviewed safety question (USQ).

In order to resolve this disagreement regarding the USQ, PG&E has submitted LAR 98-03 to change Technical Specification 3/4..6.2.1, "Containment Spray System," to clarify that containment spray is not required to be actuated during recirculation, but may be actuated at the discretion of the Technical Support Center.

2. Outage Safety Plan Schedule Change 1R8-05: Backseating of RCP 1-4 in Mode 5
(Units 1 & 2) (LBIE Log No. 97-115)

Reactor coolant pump (RCP) 14 will be backseated to work on the seal package. The Outage Safety Plan and schedule requires the RCPs to be coupled when the reactor coolant system (RCS) is intact. The reason is that, upon loss of residual heat removal (RHR), the RCS will eventually pressurize, lfting the RCP off the backseat, which would result in a small cold leg opening. A cold leg opening would lead to an inventory loss, which could eventually lead to core uncovery.

Safety Evaluation Summary

The Outage Safety Plan is not described in the FSAR Update. Additionally, maintenance of the RCP seals is not covered in the FSAR Update. This condition/configuration will not affect the safe operation of the plant. A contingency is provided to maintain the backseated condition of RCP 1-4 in order

to maintain RCS integrity to the low temperature overpressure protection (LTOP) pressure-operated relief valve (PORV) lift point. This will allow for core coolng to occur per normal shutdown operation scenarios. This contingency consists of one 20-ton hydraulic jack between the pump and motor shafts. This contingency can be installed within a very short duration relative to the time to boil.

3. Use of RM-87 as an Alternate to RM-29 in Emergency Plan (Units 1 & 2) (LBIE Log No. 96-039)

This licensing basis impact evaluation (LBIE) was prepared for Plant Staff Review Committee approval to formally allow RM-14/87 to be recognized and used as an alternative to RM-29 in the Emergency Plan for monitoring the plant vent effluent variable. The emergency action level classification chart in Emergency Procedure (EP) G-1 states that an unusual event must be declared if both the safety parameter display system and RM-29 lost all display capabilities. Since RM-14/87 has the same instrument classifications and covers a wider instrument range with better accuracy, it should be considered an alternate to RM-29, therefore, preventing unnecessary emergency declarations if RM-29 and SPDS were not available.

Safety Evaluation Summary

The LBIE covered a 50.59 review and a 10 CFR 50.54(q). Since no change to the facility or operation was proposed, and the RM-14/87 monitors met the requirements of the existing RM-29, the 50.59 did not reveal any unreviewed safety question issues. The 50.54(q) determined that the clarification in EP G-1 and Surveillance Test Procedure (STP) G-16 to also use RM-14/87 still meets the intent of NUREG-0654, 10 CFR 50.47(b)(4) and 10 CFR 50, Appendix E because it does not alter the emergency classification or condition but adds an additional method of performing the function.

4. Undampered Ventilation Opening in the Unit-2 Auxiliary Feedwater Pump Rooms FHARE 10, Rev. 3 (Unit 2) (LBIE Log No. 98-071)

This fire hazards Appendix R evaluation (FHARE) revision addresses a previously unevaluated seismic support strut penetration through a ventilation damper between the two auxiliary feedwater pump rooms. This Appendix R fire barrier is rated as a 1-hour barrier. The subject penetration is sealed with an untested 4-in. thick configuration consisting of fire resistant materials of calcium silicate board and silicone foam sealant around the 3-1/2-in. diameter schedule 80 steel pipe strut.

Safety Evaluation Summary

The maximum equivalent fire duration in either fire area/zone on each side of the barrier is 20 minutes, a low fire severity; there are no combustible materials in

the vicinity of the strut on either side of the barrier. Detection and automatic suppression features exist on both sides of the barrier. In the unlikely event of a fire affecting the fire area/zone on both sides of the barrier, the consequences would not be different from those evaluated and found acceptable in the FSAR Update.

5. Requirements for Non-Class IE Containment Overcurrent Protection
QE 10011535 (Units 1 & 2) (LBIE Log No. 97-098)

Supplementary Safety Evaluation 8 (SSER 8), dated November 15, 1978, required that primary and backup non-Class 1E penetration overcurrent protection be capable of remaining operable during an operating basis earthquake (OBE). The safety evaluation is to demonstrate that the existing documentation and analyses are sufficient to meet the intent of the SSER 8 requirements to protect the penetrations in the event of an OBE.

Safety Evaluation Summary

There is no licensing basis accident in Chapter 15 of the FSAR Update that postulates an accident during or after a seismic event. Seismic qualification of the reactor coolant pressure boundary precludes a loss-of-coolant accident occurring as a result of a seismic event. Redundant overcurrent protection assures that containment integrity is maintained and the single failure criterion is met during an accident. A failure modes and effects analysis demonstrates that there are no credible failure modes that would result in a failure to protect the penetrations for a fault inside containment after an OBE. The radiological consequences of analyzed events requiring containment integrity are not increased. There are no new accidents or increased consequences of malfunctions of equipment important to safety. There is no impact on the Technical Specifications or their Bases.

6. Unqualified Penetration Seals in the ASW Pump Room Barriers
FHARE 114 (LBIE Log No. 97-044)

Fire hazards Appendix R evaluation (FHARE) 114 evaluates the ability of the unqualified penetration seals in the auxiliary saltwater (ASW) pump room barriers to protect one train of safe shutdown circuits from the effects of a fire. FSAR Update Appendix 9.5A has been revised accordingly to address the non-rated seals.

Safety Evaluation Summary

The non-rated seals are installed in a configuration that is not supported by a qualified fire test. Therefore, a fire rating cannot be assigned to these configurations. In accordance with the fire hazards analysis in Appendix 9.5A of the FSAR Update, the ASW pump vaults are separated from other fire areas by

a 3-hour-rated fire barrier. FHARE 114 concludes that the effectiveness of the barrier is not reduced by the use of the non-rated seals. Therefore, no unreviewed safety question is involved.

7. CCW Heat Exchanger Rooms - Fire Area Boundary
FHARE 120, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-042)

This fire hazards Appendix R evaluation (FHARE) evaluates the acceptability of combining Fire Areas 14-E (component cooling water (CCW) Heat Exchanger Room) and 14-A (Main Turbine Building) in Unit 1 and combining the equivalent Unit 2 areas 19-E and 19-A. This would result in the existing barrier between the two areas no longer being controlled as an Appendix R barrier.

Safety Evaluation Summary

A review of the safe shutdown capabilities associated with these fire areas shows that there are no safe shutdown features in the CCW Heat Exchanger Room that are redundant to those in the Main Turbine Building, and vice versa. The ability to achieve and maintain safe shutdown will not be affected by this combining of areas. By combining these two areas in each unit, there is no intention to change the existing combustible loading in either area (which is already low), nor to change the existing fire detection and suppression features in either area, nor to reduce the effectiveness of the existing barrier between the two present areas.

8. Pipe Penetration Seals Through Plaster Walls in the Unit 1 AFW Pump Rooms
FHARE 121, Rev. 0 (Unit 1) (LBIE Log No. 98-073)

Numerous (~45) penetrations exist in three of the Appendix R fire barriers through plaster walls of the auxiliary feedwater pump rooms. These penetrations are located in the 1- and 2-hour rated sections of the fire barriers. The details of these penetrations are very similar to a tested configuration; but, not being identical, they are considered as untested, requiring a fire hazards Appendix R evaluation (FHARE).

Safety Evaluation Summary

The combustible loading in the related fire areas results in a maximum equivalent fire duration of much less than 1 hour, the largest being 19 minutes, The similarities of the design of these penetrations to the tested 3-hour configuration provides a level of protection easily commensurate with these low fire severities. In addition, detection and suppression equipment exists to respond to postulated fires. The FHARE evaluation of safe shutdown capabilities confirms that safe shutdown can be achieved and maintained in the event of a postulated fire.

9. Unsealed Penetrations With Fusible Link Chain Penetrants Through Fire Barriers
FHARE 123, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-039)

Small diameter (typically 3/4-in. or less), unsealed penetrations exist at various locations in DCPP, 3-hour rated, Appendix R fire barriers. These holes have fusible-linked chains passing through them associated with the fire-caused closure of roll-up fire doors. Free movement of the chain through the hole is required for the fire door actuation to occur. The wall thickness at the location of these penetrations is 10-in. minimum. They are typically high on a wall, near the top of the associated fire door.

Safety Evaluation Summary

These penetrations were provided to meet the requirements of NFPA-80, "Standard for Fire Doors and Fire Windows." For DCPP, Figure B-48 illustrates such installations. The small diameter of the hole and substantial thickness of the wall will limit the quantity of combustion products that will pass through the fire barrier while preventing flames from passing through the opening. This limited quantity of heated gasses is not expected to be great enough to raise the general area temperature or affect the operation of equipment in the unexposed compartment.

10. Unsealed Penetrations Through Barrier 119
FHARE 124, Rev. 0 (Unit 1) (LBIE Log No. 98-040)

Two unsealed penetrations exist in the CCW Pump 1-3 room floor, a 3-hour rated Appendix R fire barrier. The steel sleeves in the penetrations extend 4-in. above the floor level. The fire hazards Appendix R evaluation (FHARE) evaluates this condition between Fire Zone 3-J-3 above and fire Zone 3-C below.

Safety Evaluation Summary

Supplemental Safety Evaluation Report (SSER) 23 previously accepted the use of curbing around floor openings as contributing to the prevention of fire spread from flammable liquids. These two sleeved penetration configurations are consistent with the justification/reasoning given in SSER 23: the 4-in. high sleeves will prevent the flow of combustible liquid (lube oil) from the CCW pump area to the zone below. The total combustible loading in both the upper and lower areas is low (i.e., equivalent fire severity of less than or equal to 15 minutes). Fire detection and suppression systems exist in both zones. There is no redundant safe shutdown equipment in the two fire zones associated with these penetrations. A fire originating in the lower area is no more likely to compromise safe shutdown functions in the CCW pump room above, especially since a fire in the lower zone can only subject one of the penetrations to a fire since there is a wall between the two penetrations below the floor.

11. Lesser-Rated Plaster Blockouts and Penetration Seal Configurations
FHARE 125, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-041)

The fire barrier between each Unit's turbine-driven auxiliary feedwater pump room and the liquid holdup tank (LHUT) room is an Appendix R, 3-hour rated barrier. An approximately 2½ by 5 foot opening exists in each of these barriers; the opening is sealed with a 2-hour rated gypsum plaster seal assembly.

Safety Evaluation Summary

The LHUT area has manual suppression equipment and a combustible loading with an equivalent fire duration of only ½ minute; each pump room has area-wide detection and suppression equipment and a fire loading with an equivalent fire duration of less than 20 minutes. In the unlikely event a fire breached the subject boundary, safe shut down would not be compromised since no redundant safe shutdown components exist in the adjacent areas.

12. HVAC Ducts Through Modified Unrated Hatches
FHARE 126 (Units 1 & 2) (LBIE Log No. 98-101)

The 3-hour rated, Appendix R floor of each Unit's Cable Spreading Room (CSR) contains an equipment hatchway which is closed by the use of 1-in. steel hatch covers. This is an unrated configuration that was approved as a deviation in Supplemental Safety Evaluation Report (SSER) 23 (pages 9-18, -19, -31 and -32). A portion of the hatchway is now occupied by three heating, ventilating, and air conditioning ducts which penetrate vertically through this area. The ducts contain rated fire dampers but the exteriors of the ducts, though enclosed with heavy gauge angle steel at the penetration, are not sealed using a rated configuration.

Safety Evaluation Summary

The replacement of one of the hatch cover sections with the fire-dampered ducting does not change the basic fire barrier configuration. The discussions, evaluations, and conclusions in the original SER are still valid for this revised condition: the lower area is of low fire severity and contains smoke detection leading to an early manual response for suppression; though the upper area has a higher equivalent fire duration, it contains heat and smoke detection and an automatic CO_2 suppression system; smoke and hot gases from a fire in the upper area would rise away from the floor penetration preventing combustion products from moving into the area below. Though both fire areas contain safe shutdown circuits, shutdown capability remains intact should a fire in either area occur, due to redundant circuits and/or manual actions for mitigation.

13. Non-Rated Pipe Penetrations in Ceiling of Unit 1 Turbine-Driven Auxiliary Feedwater Pump Room
FHARE 128, Rev. 0 (Unit 1) (LBIE Log No. 98-049)

A 3-hour rated ceiling exists for the turbine-driven auxiliary feedwater pump room. The firewater pump room is located above this area. Firewater piping (8-in.) passes through 12-in. diameter sleeved penetrations in this ceiling at two locations. A pipe anchor constructed with 3/8-in. steel plate is built directly above each sleeved opening, completely sealing the top of each penetration.

Safety Evaluation Summary

Since the pipe anchor completely seals the penetration, smoke, hot gases, combustible liquids, and fire suppression water is prevented from passing through the barrier. The maximum equivalent fire duration for the two, adjacent areas is 19 minutes; the combustibles are not near to the penetrations. Each area has fire detection and suppression equipment. No safe shutdown redundancy exists between the two areas.

14. Duct Penetrations Through Common Walls Associated With Fire Zones 8-A, 8-D, 8-E, 8-F, 8-G, and 8-H
FHARE 129, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-035)

A return air duct within each unit's half of the control room passes through two Appendix R fire barriers without fire dampers installed within the plane of the barriers and without the required fire resistance of the ducting.

Safety Evaluation Summary

The subject, 16-gauge ducts are well-fitted to the wall penetrations with fire stops and are seismically supported. The fire hazards in the adjacent areas are limited (i.e., maximum equivalent fire duration of 50 minutes) such that the 3-hour rating is regarded as conservative for the existing hazards. Per the NFPA Fire Protection Handbook, ducting of this construction can be credited for fires of up to 1 hour equivalent duration. Detection and suppression equipment is located in or immediately adjacent to these control room fire areas. Since the control room is continuously occupied, any fire originating in these areas will be quickly detected and suppressed by plant personnel.

15. Unique Blockout Penetration Seal Through Barrier Between the Unit 2 Turbine Building and Containment Penetration Area
FHARE 13, Rev. 3 (Unit 2) (LBIE Log No. 98-051)

Two, 28-in. diameter main steam lines pass through a 3-hour rated wall between the containment penetration area and the turbine building. Due to seismic supports on the piping and thermal movement of the piping, an alternate

configuration for the penetration seal is provided. A combination of 34-in. diameter Pyrocreted steel sleeves with double flexible boot seals is provided around each line on the turbine building side of the barrier.

Safety Evaluation Summary

The combustibles in each area translate into an equivalent fire duration of much less than 45 minutes, giving a low fire severity. These combustibles are at least 35 feet away from the penetration on the turbine building side and at least 20 feet away from the penetration on the containment penetration room side. Both areas contain automatic, water suppression systems; a partial area smoke detection system above cable trays is provided in the containment penetration area. Systems required for safe shutdown either have adequate redundancy available or credit is being taken for manual operator actions. As a fire would be confined to one fire area, redundant safe shutdown equipment would remain available.

16. Inaccessible Jumbo Duct Penetrants
FHARE 130, Rev. 0 (Unit 1) (LBIE Log No. 98-084)

Three 4-in. by 4-in., steel tubes ("jumbo ducts"), welded side-by-side, penetrate the 36-in. thick concrete, 3-hour rated fire barrier between the cable spreading room (CSR) and the containment penetration room. Due to their partial physical inaccessibility on one side of the barrier, a penetration seal configuration cannot be assigned. Glass-like epoxy resin is used to seal the cables inside the ducts.

Safety Evaluation Summary

These seal assemblies are similar to adjacent assemblies that have been tested to verify their ability to withstand a 3-hour fire. In fact, in some respects, the subject assemblies are more conservatively configured than the tested assemblies. The maximum fire severity is on the CSR side of the barrier and has an equivalent fire duration of 44 minutes. Most of the combustible material in this area is electrical wiring insulation in cable trays; however, fire stops along the tray runs would be expected to limit the fire to a localized area. Fire detection and suppression equipment exists in both fire areas. Redundant safe shutdown equipment will remain adequately protected as previously credited in the licensing basis.

17. Unrated HVAC Duct Penetrations
FHARE 136, Rev. 0 (Units 1 & 2) (LBIE Log No. 98-109)

Fire hazards Appendix R evaluation (FHARE) 136 evaluates the acceptability of having unsealed duct penetrations in rated fire barriers located in Fire Areas/Zones 13D, 12A, 13E, 12B, 24D, and 23A. FSAR Update Appendix 9.5A has been revised accordingly to address the unsealed penetrations.

Safety Evaluation Summary

The unsealed duct penetrations in the specific fire areas/zones have been evaluated and determined to not adversely impact the DCPP fire protection program. The combustible loading is low in the affected areas and the existing fire protection features are adequate. Therefore, it is concluded that no unreviewed safety question is involved.

18. Concrete Equipment Hatches
FHARE 14, Rev. 3 (Units 1 & 2) (LBIE Log No. 98-072)

Concrete hatches are installed in the plant to aid in equipment access. Some of these are located in 3-hour rated Appendix R fire barriers. The evaluation was originally written to evaluate the existence of up to 2-3/8-in. wide, unsealed gaps around the hatch perimeters. This revision added 4 hatches to those evaluated under this fire hazards Appendix R evaluation (FHARE). These hatches are at the top of each of the residual heat removal (RHR) pump/heat exchanger vaults. Additionally, for the hatches previously covered by the FHARE, revised equivalent fire severities and safe shutdown equipment discussions are provided.

Safety Evaluation Summary

The revisions to discussions related to the original hatches and those being added to this FHARE's scope do not change the reasoning or conclusions of the previous 50.59 evaluation: (1) the revised combustibles loading still results in low equivalent fire severities; and (2) the RHR pump and heat exchanger rooms have partial smoke detection and water spray suppression. Therefore, due to the automatic and manual fire protection features, lack of continuity of combustibles, tortuous path of travel for a fire on an upper level to propagate downward to affect redundant safe shutdown. The only redundancy is the H Bus circuits located on the 76 foot elevation in fire zone 10 (20) and the G Bus circuits on the 107 foot elevation in fire zone 12-B (23-B). The spatial separation between these two elevations represents a tortuous path for products of combustion or fire propagation. Therefore, the capability to achieve safe shutdown is not affected.

19. CCW-1-TCV-130 Replacement (HOT TAP)--DCP M-049319
TES 2-001-N (Units 1 & 2) (LBIE Log No. 97-087)

This design changed replaced the existing TCV-130 with one having better control characteristic for the given system parameters. Changes in the cooling water flow to the let down heat exchanger caused letdown temperature fluctuations resulting in boron concentration/reactivity. The existing TCV-130 was too large to maintain fine control, operating in the lower 2 percent of its

control range. To allow the replacement of the valve without draining header "C" it was necessary to use a HOT TAP to install a by-pass line and smaller TCV-130. A HOT TAP allows the installation of branch connections to existing pipe while the system is "LIVE" which was required because component cooling water (CCW) for the spent fuel pool can not be isolated, even during outages.

Safety Evaluation Summary

The CCW is a safety related system which during refueling outages is relied upon to cool the spent fuel pool. Per FSAR UpdateTable 9.2-7 there are 5 CCW system malfunctions and consequences. Of these, two where potentially effected by the use of a HOT TAP to install the by-pass line. CCW system leakage was eliminated because the HOT TAP machine and associated fittings, flanges and valves where rated for the design pressure and temperature of the system. As a precaution the HOT TAP machine was hydrostaticlly tested prior to breaching the CCW system. The second possible effect was CCW heat exchanger tube rupture which could allow RCS inleakage into the CCW. Due to the relatively small size of debris anticipated in the HOT TAPPING process and the configuration of the system it was determined to be highly unlikely that a tube rupture could occur. Even if a tube where to rupture this would not effect the primary safety function of the CCW to cool safety related loads during Modes 1-4. As a precaution the work was to be completed during Mode 0 (Reactor Defuelled). Completing the work during Mode 0, should a tube rupture, there would not have been inleakage of RCS into the CCW because RCS is depressurized during refueling. Based on the above conclusions the possibility of an accident of a different type than any previously evaluated in the FSAR Update was not created.

20. Non-Rated Features in the Units 1 and 2 Centrifugal Charging Pump Rooms
FHARE 25, Rev. 3 (Units 1 & 2) (LBIE Log No. 98-080)

An additional, triangular-shaped, nonrated penetration of approximately 6-in. by 12-in. is included in this Fire Hazards Appendix R Evaluation (FHARE). It is immediately adjacent to one of the undampered duct penetrations evaluated in an earlier revision of this same FHARE. One side of the penetration is completely covered by a section of structural steel angle. In addition, the combustible loading description for all the related fire areas was updated and a safe shutdown capability analysis was provided.

Safety Evaluation Summary

Using the same reasoning as that provided for the originally-evaluated adjacent duct penetrations, the additional penetration does not create an unreviewed safety question: there is low equivalent fire duration in the related fire zones, automatic fire detection and wet pipe sprinklers are present, a minimum spatial separation between redundant safe shutdown components of 30 feet exists, and

there is an absence of significant quantities of combustibles near the penetrations in Fire Zone 3-C.

21. Undampered Duct Penetrations in Fire Areas/Zones 4-B, 19-E, and TB-7/19-A
FHARE 58, Rev. 3 (Unit 2) (LBIE Log No. 98-117)

Fire hazards Appendix R evaluation (FHARE) 58 was revised to acknowledge the absence of a penetration seal around the ductwork that was previously evaluated for not having fire dampers at the Appendix R fire barriers. Combustible loading and the resulting equivalent fire durations were also revised for the related areas, all of them still remaining in the low fire severity category. A more detailed description of fire protection features in these areas was also provided as well as a safe shutdown capability analysis.

Safety Evaluation Summary

The same fundamental arguments for the original conclusion of no unreviewed safety question still apply: combustibles loadings having low fire severities, automatic smoke detection and sprinkler systems, manual fire fighting capabilities, and the ability to achieve safe shutdown even in the unlikely event a fire was to breach the subject boundary.

22. Lead Shielding Request Per Procedure RP1.ID2
TSR 97-011, Rev. 0 (Unit 1) (LBIE Log No. 97-059)

To allow the plant to install and remove temporary lead shielding in Unit 1 containment for Lines 508, 509, 927, and temporary steel attached to containment annulus structure, located above the residual heat removal (RHR) sump in containment. Shielding will be installed in Modes 5 and 6 only. Shielding will be removed prior to entering Mode 4. Shielding will be installed on operable piping which creates a condition that might affect safe operation of the plant not evaluated in the FSAR Update.

Safety Evaluation Summary

Seismic calculations demonstrate that the components are not adversely affected. The tie-down arrangement of the lead blankets will be such that it will not create a new source, per seismically induced systems interaction, or affect any other safety-related systems, structures or components. The only potential concern would be for the subject residual heat removal lines to suffer a medium energy line break, near the shielding location. In this case during Mode 5 operation, the residual heat removal sump is not required to mitigate the line rupture. The impact of the shielding on the sump could render the sump inoperable, but it would not affect the safe shutdown of the plant. The DCPP accident analysis does not postulate a Mode 5 loss-of-coolant accident or line

break. Based on the above criteria and justification, an unreviewed safety question is not involved.

23. Mode 4 to Mode 3, Obtain New RVLIS DP3 coefficients
AR A0425503 (Unit 1) (LBIE Log No. 97-095)

This LBIE was a part of Attachment 9.10 of Operations Procedure OP L-0 that obtained Plant Staff Review Committee approval for Unit 1 to transition from Mode 4 to Mode 3 with Train A of reactor vessel level indication system (RVLIS) out-of service. RVLIS is required per Technical Specification (TS) 3.3.3.6 for Modes 1-3.

Train A of RVLIS was required to be out-of service to perform the data collection required to obtain new DP3 coefficients while the plant heats up from refueling to Mode 3, normal operating pressure/normal operating temperature conditions.

The action to reperform the DP3 curve was corrective action from NCR N0002016.

Safety Evaluation Summary

The LBIE screen for this condition screened “Yes” as a change to the system operation as described in the FSAR Update. The safety evaluation determined that an unreviewed safety question is not involved based on the Technical Specifications allowing the plant to transition modes while under Action (A) for TS 3.3.3.6 for RVLIS (ie TS 3.0.4 exempt). With Train B fully in service during this evolution and the system exempt from the provisions of TS 3.0.4, the facility design or license was not impacted.

24. Steam Generator Tube Support Plate Thin or Missing Ligaments
AR A0432415, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-099)

Thin or missing steam generator (SG) tube suport plate (TSP) ligaments were identified by review of DCPP Units 1 and 2 SG eddy current data and confirmed by visual inspections of DCPP Unit 1 SG TSPs conducted in 1R8.

Safety Evaluation Summary

Operation of the DCPP Units 1 and 2 SGs with thin or missing TSP ligaments will not adversely affect SG tube structural and leakage integrity during normal operation and accident conditions. An active tube wear mechanism is not occurring at locations of thin or missing TSP ligaments, and no additional tubes are expected to experience deformation during a postulated loss-of-coolant accident plus seismic event.

25. Continued Operation With Cable Dampers for Steam Generator U-Bends
FTI Document 51-1264525, Rev. 1 (Units 1 & 2) (LBIE Log No. 98-023)

The subject of this licensing basis impact evaluation (LBIE) was the qualification of steam generator (SG) U-bend dampers designed by Westinghouse and installed in eight potentially susceptible tubes (November 1988 in the Unit 2 second refueling outage and October 1989 in the Unit 1 third refueling outage) to increase margins against flow-induced vibration in response to NRC Bulletin 88-02. This LBIE extended the qualification of the damper to full lifetime without the need for inspection based on further damper testing and the supporting 50.59 evaluation performed by Framatome Technologies.

Safety Evaluation Summary

Tubes that were susceptible to flow-induced fatigue cracking (WCAP 12064) have been plugged and dampened by installation of Westinghouse cable dampers to meet the requirements of NRC Bulletin 88-02. Therefore, in the dampened tubes, the tube plugs act as the reactor coolant system (RCS) pressure boundary, and the damper will not affect the function of the plugs. The increased wear in the damper/tube system has been evaluated through testing and analysis and has been determined to not affect the dynamic characteristics of the system or result in failure of the system. The relevant accident that has been previously evaluated in the FSAR Update is a SG tube rupture (SGTR). The probability of occurrence of an SGTR event is not increased because the dampers are qualified for continued performance of their safety function. Based upon the above criteria and justification, an unreviewed safety question is not involved. Also, a change to the Technical Specifications is not involved.

26. Determination of the Uncovered Screen Area and Pressure Drop Across the Screens in the Recirculation Sump After Paint and Insulation Severs From Objects Inside Containment During Post-LOCA Environment
Calculation M-591, Rev. 11 (Units 1 & 2) (LBIE Log No. 97-100)

Calculation M-591 was inconsistent with insulation assumptions described in the FSAR Update. It was shown that the sump analysis did not conflict or invalidate FSAR Update statements regarding the acceptability of paint chips plus transport of 100 percent of damaged insulation during a large break loss-of-coolant accident (LOCA). Instead, this calculation revision identified that a more limiting scenario exists, shredded insulation during a small break LOCA, and evaluated that scenario with new assumptions about insulation transport. Two key changes to the evaluation methodology were made: containment flood levels were determined for small break LOCAs, and less than 100 percent of fiberglass insulation in the form of shredded debris was assumed to reach the sump and deposit evenly over the screen. The impact of paint chip and fiberglass insulation debris were thus evaluated together for the first time.

Safety Evaluation Summary

LOCAs are the only accidents evaluated in the FSAR Update that rely upon sump operability. The function of the sump is to screen out debris while providing sufficiently low flow resistance such that the residual heat removal (RHR) pumps will not draw down the sump level and cavitate. The FSAR Update statement that transport of 100 percent of loosened fiberglass insulation concurrent with transport of degraded paint particles would not prevent the sump from being operable only applied to large break LOCAs with the assumption that the insulation remained intact. Calculation M-591 now credits less than 100 percent of insulation transport due to obstacles, the high specific gravity of fiberglass, and the low flow velocities through the containment during recirculation. A more limiting scenario was identified for screen operability, a small break LOCA with shredded fiberglass insulation spread out over the entire screen, and M-591 Revision 11 demonstrated that the sump remains operable under this new scenario.

27. Fiberglass Insulation Debris From HELB Inside Containment
Calculation N-042, Rev. 1 and N-051, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-093)

Calculations N-042 and N-051 were revised to incorporate the latest design basis methodology for determining the quantity of fiberglass insulation debris generated due to various high energy line breaks (HELBs) inside containment. The leak-before-break (LBB) methodology was incorporated into the calculations to eliminate the dynamic effects of reactor coolant loop HELBs on fiberglass insulation, and certain non-terminal end breaks were eliminated from consideration based on the latest jet impingement study and pipe whip study. Although use of the LBB methodology was approved by the NRC for DCPP in March 1993, Revision 11A of the FSAR Update did not reflect this revised licensing basis, so this safety evaluation was required to take credit for LBB in the insulation calculations.

Safety Evaluation Summary

General Design Criterion 4 states that structures, systems and components shall be appropriately protected against the dynamic effects, including missiles, pipe whip, and discharging fluids that may result from equipment failures outside the nuclear power unit. However, the dynamic effects associated with postulated pipe ruptures in the nuclear power unit may be excluded from design basis when the analysis reviewed and approved by the NRC demonstrates that the probability of a fluid system rupture is extremely low under conditions consistent with the design basis for the piping. The NRC determined that class 1 piping breaks at DCPP are sufficiently low that the dynamic effects associated with postulated primary pipe breaks need not be a design basis. The NRC approved DCPP's LBB evaluation in March 1993. Thus, elimination of the dynamic effects

of postulated RCS loop piping ruptures from fiberglass insulation debris evaluations is within the licensing basis of the plant.

28. LHUT Dose Reanalysis/Calculation N-160
Calculation N-160, (Units 1 & 2) (LBIE Log No. 97-092)

FSAR Update Section 15.5, Liquid Holdup Tank (LHUT) Rupture, was reanalyzed to conform with Regulatory Guide (RG) 1.29, "Seismic Design Class." RG 1.29 specifies that some systems must meet seismic qualification criteria or the design basis accident offsite dose consequences must be less than 0.5 rem whole body. The LHUTs and associated piping were purchased seismic qualified but not maintained seismic qualified. The dose consequences from the original LHUT rupture was 1.44 rem. The reanalysis results are 0.152 rem. Therefore RG 1.29 is met.

Safety Evaluation Summary

The reanalysis of the postulated offsite dose from a LHUT rupture does not involve any changes to plant systems, structures or components. The reanalysis is based on conservative assumptions with respect to the original analysis contained in the FSAR Update. The reanalysis results show a reduction in offsite dose rates from the postulated LHUT rupture. Thus, the consequences of the LHUT rupture previously evaluated in the FSAR Update are reduced, not increased.

29. Control Room Vent
AR PK15-06, Rev. 8 (Unit 2) (LBIE Log No. 97-144)

This procedure revision revised the response to losing subtrains of control room ventilation system (CRVS) cooling, as described in the FSAR Update. Previously, there was no guidance provided for this event, since there are four equally redundant subtrains available to perform CRVS functions. However, to prevent the possibility of overlooking the FSAR Update-described response, these actions were added to the procedure.

Safety Evaluation Summary

Since the proposed procedure revision adds the detail as described in the FSAR Update, there is no change to the facility or operation as described in the FSAR Update. The evaluation was performed since the FSAR Update describes response to loss of all CRVS in moderate detail. An unreviewed safety question is not involved.

30. Revision of the Bases for Technical Specification 3/4.9.2, "Refueling Operations - Instrumentation"
Technical Specification Bases 3/4.9.2 (Units 1 & 2) (LBIE Log No. 97-219)

The revision of the Bases for Technical Specification (TS) 3/4.9.2, "Refueling Operations - Instrumentation" allows use of an alternate source range (SR) monitor during Mode 6 (refueling) in the event one of the two normal SR channels becomes inoperable. (Note: This has already been reported to the NRC in Letter DCL-97-035, dated March 18, 1997)

Safety Evaluation Summary

The use of alternate SR indication provided by post-accident neutron flux monitors is equivalent to use of a portable detector allowed by TS Bases per License Amendments 46 and 45. This condition does not involve an unreviewed safety question. PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by this TS Bases revision.

31. Revision of Technical Specification Bases 3/4.7.3 and 3/4.7.12 - Change Component Cooling Water System Design Basis Temperature
Technical Specification Bases 3/4.7.3 and 3/4.7.12 (Units 1 & 2) (LBIE Log No. 97-221)

The change to Technical Specification (TS) Bases 3/4.7.3, "Vital Component Cooling Water," and 3/4.7.12, "Ultimate Heat Sink," increased the maximum temperature at which the component cooling water (CCW) system may operate after a design basis event from 132°F for 120 minutes to 140°F for six hours after the event, returning to a maximum of 120°F thereafter. This revision reflects upgraded qualifications of CCW components and equipment cooled by CCW to show that they can function with the higher temperature cooling water. An administrative change to relocate the temperature limit from Bases 3/4.7.12 to Bases 3/4.7.3 was also made to improve consistency.

Safety Evaluation Summary

PG&E has performed a detailed, component level review of the CCW equipment, support system equipment, and the equipment cooled by CCW. Each device was reviewed using vendor information as needed, and found to function properly with the increased cooling water temperature. The change did not require modification to any equipment or system, other than a minor adjustment to CCW heat exchanger auxiliary saltwater (ASW) discharge throttle valves to mitigate possible cavitation and resetting a post-accident sampling system (PASS) temperature switch setpoint to accommodate the new temperature limit. These valves are normally throttled already, and the required minimum valve position imposed by this change is within the range of the current normal operation of these valves. The imposition of these valve position requirements

serves to minimize potential cavitation effects and has no detrimental impact on the capability of the ASW to perform its normal and emergency functions. Based on detailed evaluations of all affected systems, components, and structures, it has been demonstrated that they will perform their intended safety functions with the increased CCW water temperature conditions.

32. Evaluation of Zinc Addition in Cycle-9 at Diablo Canyon Unit 1
Westinghouse Letter SECL-97-207 (Unit 1) (LBIE Log No. 98-038)

The addition of zinc to the reactor coolant system (RCS) will be done for the purpose of decreasing the incidence of primary water stress corrosion cracking in the steam generator U-tubes. Zinc acetate will be injected via the chemical and volume control system (CVCS) system to achieve an RCS zinc concentration of 35-40 ppb during a nine month trial period. A secondary benefit will be the reduction of radiation fields in the RCS. Tests will be performed to determine its effectiveness.

Safety Evaluation Summary

The injection of zinc into the RCS has not previously been done at DCPP nor is it described in the FSAR Update. Analysis of zinc injection performed at Farley 2 demonstrated that zinc did not have a deleterious effect on the function or operation of any RCS components with the potential exception being fuel. A root cause evaluation concluded that zinc may have a small detrimental effect on fuel cladding oxidation. For this reason, a conservative penalty was included in the fuel analysis for the Unit 1 Cycle 9 core. Results of the analysis demonstrate that all fuel design criteria are still met.

Consideration for the impact of zinc on post-accident hydrogen, LOCA heat transfer, containment sump pH, source term, and RCS dilution was all found to be insignificant. Consequences of an accident will therefore not be increased by the addition of zinc.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL-89-206	2-2	Violation (EA 89 85): 1. The design basis requirements for the Component Cooling Water (CCW) system described in the Final Safety Analysis Report (FSAR), Section 9.2.2.2, specifies that one CCW pump and heat exchanger are sufficient to provide decay heat removal and essential component cooling in the event of a design basis loss of coolant accident (LOCA) provided that a second CCW heat exchanger is placed in service within 20 minutes. Contrary to the above, as of January 26, 1989, the requirement that, within 20 minutes following a LOCA, operators place a second CCW heat exchanger into service, had not been translated into appropriate procedures or instructions. 2. The design basis for the Component Cooling Water system, as described in the FSAR, Section 9.2.2, specifies that, following a design basis Loss of Coolant Accident (LOCA), sufficient cooling will be supplied to vital loads. Licensee calculation M 464, dated August 17, 1983, and internal letter No. 84000312, dated February 14, 1984, specify that to meet the design basis, two CCW heat exchangers must be in service whenever CCW pump 1 1 or 1 2 is not available. This calculation is also applicable to Unit 2 (pumps 2 1 and 2 2). Contrary to the above, as of January 26, 1989, the requirement to have two heat exchangers in service with CCW pump 1 1 or not available had not been translated into appropriate specifications, drawings, procedures, or instructions. Between July 20, 1984 (initial entry of Diablo Canyon Unit 1 into Mode 3) and January 26, 1989 (NRC Safety System Functional Inspection team discovery date), the licensee routinely removed CCW pumps 1 1 or 1 2, and 2 1 or 2 2, without putting a second CCW heat exchanger into service. For the Violation (EA 89 85), DCPP made corrective actions. Full compliance with the design basis requirements for the CCW and ASW systems was achieved on February 2, 1989, when appropriate plant procedures were revised to include the operating requirements identified in Violation I.A. As noted above, additional actions to prevent recurrence are in progress as part of the Configuration Management Program.
DCL-89-235	4	EVALUATION OF COMMERCIAL GRADE REPLACEMENT PARTS PRESENTLY INSTALLED IN THE AUXILIARY SALTWATER (ASW) AND COMPONENT COOLING WATER (CCW) PUMPS Quality Assurance Audit 88244S of Sulzer Bingham International (SBI) on September 21-22 and October 4-5, 1988, identified significant deficiencies in the SBI quality assurance program. Replacement parts for the Diablo Canyon ASW and CCW pumps, although ordered nuclear safety related, were supplied by SBI under a commercial grade quality assurance program.

DCL #	Page	Descriptions
	7	CCW Pumps The CCW pumps circulate clean water in the closed loop CCW system. The only potentially significant difference between their normal duty and their accident duty is the potential seismic loading. (The change in CCW temperature and system head are not significant factors in accessing the adequacy of commercial grade parts.) Seismic Qualification Reports 4.1, 4.2, 13.1, and 13.4 have been reviewed and it has been concluded that, with the exception of the pump casing to pedestal bolts, the seismic loading on the CCW pumps and motors is an insignificant factor in assessing the adequacy of commercial grade parts. For the pump and motor, sufficient margin exists between the calculated and allowable stresses and deflections to account for potentially degraded commercial grade parts supplied by SBI. However, for the ASTM A325 bolts that attach the pump casing to the SBI supplied pedestal, sufficient margin does not exist to compensate for the potential of incorrect bolts strength. To assure that the correct bolts have been used, an inspection has been performed and it has been confirmed that the bolts are stamped “A325”. In summary, the seismic review concluded that (with the exception of the bolts discussed above) even degraded commercial grade SBI parts would withstand the seismic loading. Therefore, demonstration that the parts are adequate for normal operation is sufficient to assure the pumps are capable of performing their safety related functions. The CCW impeller is a cast bronze, not requiring heat treatment. Therefore, the problem of inadequate heat treatment, as experienced with the ASW pump impellers, is not applicable to the CCS pump impellers. In conclusion, as was the case with the ASW pumps, the successful dedication and installation of spare parts, successful testing of the pumps, the successful day to day operation of the pumps, and the planned periodic maintenance and inspection of the pumps are sufficient to assure that the pumps are capable of performing their safety related functions for the design life of the equipment.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL 90-027	Enclosure, page 2	With respect to GL 89-13 control technique C regarding flushing and flow testing, DCPP Surveillance Test Procedure (STP) M-26, "ASW System Performance Monitoring," is performed to flow test the ASW system on a monthly basis to verify design flow capability. This monthly STP ensures that the ASW cooling loops are flushed and flow tested at operating flow, and that no significant fouling or clogging exists in the system. Additionally, the component cooling water (CCW) heat exchangers have pressure differential (dP) indication in the control room, which alarms at a set dP limit to alert the operators that heat exchanger cleaning is required. Upon receipt of such an alarm, work to clean the heat exchanger is initiated in accordance with Annunciator Response Procedure PK-01-01, "ASW SYS HS DELTA P/HDR PRESS." PG&E currently does not use chlorinated water during layup of the ASW system. At the present time, there is no indication that this has resulted in any additional ASW system biofouling; however, PG&E, as part of the Biofouling Task Force, will investigate the desirability of using chemical treatment and other methods during ASH system layup to control any potential biofouling.
	Enclosure, page 4	PG&E believes that the DCPP closed-cycle, safety-related heat exchangers meet the GL 89-13 exclusion criteria, and that inclusion of these in the test program is therefore not necessary. The bases for this conclusion are: the heat exchangers do not reject heat directly to the ultimate heat sink; the water in the closed-cycle systems is and always has had a corrosion inhibitor; and procedures are in place which ensure that the closed-cycle water chemistry is well-controlled. Additionally, the closed-cycle CCW system design basis specifies water pressure higher than the salt water system with which it interfaces, the water has not been subjected to significant sources of inleakage contamination, and operating history data show that the water quality has remained stable. There are a total of four open-cycle, safety-related CCW heat exchangers at DCPP. PG&E will develop and conduct a one-time heat exchanger performance test to confirm the baseline heat transfer capability of these heat exchangers. Since it is not feasible to test these heat exchangers at their design heat removal rate (normal heat loads are on the order of 10 to 20 percent of design basis heat loads), a test using high-accuracy temporary instrumentation will be implemented. However, a study performed by PG&E to determine the sensitivity of the fouling factor calculation for design basis loads using data obtained at normal heat loads shows that a one degree error in temperature measurement could result in a greater than 30 percent deviation for the calculated fouling factor. Therefore, phenomena such as thermal stratification in the CCW system heat exchanger outlet piping could introduce significant uncertainties in the test results. Small errors in ASW flow measurement also would introduce additional uncertainties. PG&E therefore cannot commit that these test results will be conclusive.

DCL #	Page	Descriptions
		However, the ASW system monitoring program as described below is an alternative method which will ensure that the ASW system operates within its design basis. To ensure that the system remains capable of maintaining design basis requirements, PG&E intends to implement an alternative monitoring program which combines flow testing, trending, inspection, and frequent preventive maintenance as permitted by GL 89-13. As noted in PG&E's response to recommendation #1 above, the CCW heat exchanger dP is monitored, and tubesheet cleaning and inspection is performed when the dP reaches a predetermined setpoint. During refueling outages, the heat exchanger waterbox coatings are inspected and the tubes are mechanically cleaned in accordance with the DCPP preventive maintenance program. Demusseling and chlorination activities are performed to prevent heat exchanger performance degradation due to biofouling. Fluid temperatures in the heat exchanger are low enough such that scaling is not a concern. Also, the ASW system is tested monthly per SIP M-26 to ensure that system flow rates meet the design basis requirements. in accordance with the DCPP preventive maintenance program, the CCW heat exchanger tubing is cleaned and the waterboxes are inspected every refueling outage. Additionally, the CCW heat exchangers are cathodically protected and the ASW system piping is lined internally and externally.
DCL 90-080	14	16. Relocation of the Non-Safety-Related Air Compressors DCP M-35366 Rev. 0 (Units 1 and 2) This modification made permanent the two rotary screw compressors being used at DCPP. One of the compressors was temporarily installed near the permanent reciprocating air compressors and the second was temporarily placed in the CCW heat exchanger tube pull space. This change permanently installs the two screw compressors along with the installation of a new air dryer and after filters in the vicinity of the permanent reciprocating air compressors.
	22	2. Temporary Procedure TB-8816, Rev. 0 (Units 1 & 2) A test of the Component Cooling Water (CCW) Heat Exchanger Inlet Waterbox Level.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL-91-053	Attachment A, Page 2	In accordance with the provisions of 10 CFR 50.59, DCPP is going to simplify the design and operation of the CFCUs by eliminating the HEPA filters and moisture separators from each CFCU and adjusting the variable inlet vanes to the fan in order to maintain the design air flow rate. The assumptions used to calculate onshore controlled containment venting are described in Table 15.5 28 of the FSAR Update, and do not take credit for the HEPA Filters or moisture separators in the accident analyses. In addition, the deletion of the HEPA filters and moisture separators from the CFCUs has been evaluated by Westinghouse, based on the assumption that modifications to the CFCUs will be made so the heat removal capability of the CFCUs and the heat load to the CCW system would not be affected. Upon removal of the HEPA filters and moisture separators, the CFCU normal and accident mode dampers would be permanently secured in positions such that normal and accident mode operations could be performed without changing damper positions. The CFCU airflow rate for both normal and accident operation after the proposed changes will be in accordance with design airflow rates. All controls associated with the CFCU dampers would also be removed. This change to the CFCU dampers would require a change to the DCPP TS 4.6.2.3 which presently requires a periodic demonstration of damper operability.
DCL-91-057	Enclosure	Abandon/Lay-up Radioactive Waste Concentrator Package DCP M-31188 Rev. 9 (Units 1 and 2) As reported in PG&E letter DCL-87-270, the radioactive waste concentrator was disconnected to allow for its conversion to a boric acid concentrator. Subsequent to the disconnection of the waste concentrator and prior to its full conversion to a boric acid concentrator, a decision was made to abandon the equipment in-place and to lay-up the waste concentrator for the present. Inasmuch as the equipment conversion originally planned had already been partially completed, the abandonment work consisted of placing the affected equipment and components in a safe condition and documenting the as-left condition. Closed the Primary Water Makeup Supply to the CCW Surge Tank DCP M-41291 Rev. 0 (Unit 1) and M-42291 Rev. 0 (Unit 2) To prevent inadvertent addition of tritiated primary water storage tank (PWST) water to the component cooling water system, a chain lock was installed on makeup valve MU-1-1561 and MU-2-1561. The Design Class II manual valve is normally closed anyway. This change is in response to NRC I&E Bulletin 80-10.

DCL #	Page	Descriptions
		Remove Moderate Energy Line Break Spray Guards providing protection for the Residual Heat Removal Pump Motors DCP M-41490 Rev. 0 (Unit 1) The 'moderate energy' seal water cooling piping below the residual heat removal (RHR) pump motors was originally thought to pose a hazard to the motor. Water spray shields, supported by the piping, were provided to protect the motors from the effects of a postulated moderate energy line break (MELB) in this piping. This DCP removes the shields. Any break in the seal water piping can only potentially affect its respective pump motor. The redundant RHR pump motor cannot be affected. This change is consistent with MELB evaluation criteria.
DCL-91-286	Enclusure, page 2	PG&E also performed ASW system open-cycle heat exchanger (also referred to as component cooling water (CCW) heat exchanger) performance tests and used a computer model to predict heat exchanger performance at design heat loads. Although these tests exhibited significant sensitivity to instrument inaccuracies due to the low heat loads measured, the computer model predicted that the heat exchanger would remove the design basis heat load at design conditions. PG&E is considering future testing and use of the computer model for heat exchanger trending. However, any future testing would be considered as additional information and an enhancement to the established alternative monitoring program. Design Criteria Memoranda (DCMs) for the ASW and CCW systems were completed in 1990. Also, the PG&E Quality Assurance Department performed a safety system functional audit and review in 1990 for these systems. No significant deficiencies were identified, and the minor problems identified during these activities were resolved in accordance with PG&E's procedures for resolving nonconforming conditions. In addition, the system and system design engineers continued to conduct their regular system walkdowns. These actions provide confirmation that the ASW system will perform its intended function in accordance with the licensing basis and that the as-built system is in accordance with the appropriate licensing basis documentation.
DCL-92-061	Enclusure, page 2	NUREG/CR-5526 provides the following generic risk reductions associated with each of the GL 91-13 proposals: • Imposing operability requirements on at least one ASW pump for the shutdown unit when the other unit is operating. Implementation of this proposal results in a generic risk reduction of 8.4E-06/RY. • Imposing cross-tie testing to ensure operability. Implementation of this proposal results in a generic risk reduction of 2.48E-06/RY. • Implementing improvements to emergency procedures to address the heat up of the CCW system and the possible heat rejection path to the spent fuel pool in the context of a loss of ASW accident. Implementation of this proposal results in a generic risk reduction of 1.21E-05/RY.

DCL #	Page	Descriptions
		PG&E believes the first risk contributor is addressed by DCPP Outage Management Policy B-26, "Maintaining Equipment Availability During Plant Outages," although it is not a TS requirement. The second and third risk contributors are addressed in PG&E's response below. Reviewing the relative importance of the three risk reduction contributors shows PG&E to be implementing the largest reduction contributor (1.21E-05/RY) and the smallest reduction contributor (2.48E-06/RY). As part of the NUREG-1421 Decision Rationale, the Staff requested that PG&E review the DCPP plant-specific design, in light of the generic PRA model, to assist in determining assumption differences that may not reflect the operating conditions at DCPP.
DCL-92-069	4 5	7. Remove the CCW Heat Exchanger Tubeside Air Removal System DCP M-41068 Rev. 1 (Unit 1) and M-42068 Rev. 1 (Unit 2) The Design Class II waterbox air removal system for the CCW Heat Exchangers was isolated from the heat exchangers and removed. Calculations and operating experience revealed that purging of air from the waterboxes occurs naturally during normal operation of the Auxiliary Saltwater (ASW) System. Existing Design Class I manual vent valves were closed to reestablish the pressure boundary integrity of the ASW System. This change eliminates a potential leak path of ASW water. The vital-powered solenoid valves deleted with the system's removal have been removed from the 10 CFR 50, Appendix R safe shutdown components list. Safety Evaluation Summary Isolation and removal of the air removal system cannot result in the occurrence of any previously analyzed accidents: the ASW and CCW Systems are accident mitigation systems and the air removal system was provided to enhance their operability. Removal of this system will not degrade the performance or challenge the function of these systems since air will be purged from the ASW side of the heat exchangers during normal ASW System operation. Heat exchanger seismic qualification is maintained. Removal of a small electrical load from the vital electrical buses will not compromise vital power integrity. The air removal system was previously a potential source of leakage from the ASW System which is now eliminated. The service air supply (now capped) for the air removal jet exhauster has not been compromised. Since: 1) ASW or CCW System integrity function and performance are not adversely affected, and 2) 10 CFR 50, Appendix R safe shutdown capability is not compromised, no new accidents or malfunctions are created. The TS bases require operability, flow capacity and redundancy of water systems providing for continued operation of safety related equipment. This modification maintains these requirements without a reduction in the safety margin.

DCL #	Page	Descriptions
	20	7. Temporary Procedure: CCW Heat Exchanger Performance Test TB-9049 Rev. 0 (Units 1 and 2) This procedure installs temporary instrumentation to support testing of the Component Cooling Water Heat Exchanger. Temporary ultrasonic flow indicators are installed on the outside of lines, temporary temperature sensors replace some permanent temperature sensors in existing thermowells, two temporary temperature sensors replace permanent thermowells and temperature sensors, and temporary flow transmitters are installed across existing flow transmitters. Safety Evaluation Summary The majority of the instruments installed by this procedure do not form any part of the existing pressure boundary. The temporary temperature sensors that replace the permanently installed thermowells and sensors are installed downstream of the Component Cooling Water Heat Exchanger where their failure will not block flow and any leakage caused by a temperature sensor failure will not affect the heat removal capability of the Component Cooling Water Heat Exchanger. The temporary instrumentation will not impact the seismic analysis and the equipment on the Auxiliary Saltwater and Component Cooling Water systems will be operated per normal plant procedures for normal or emergency conditions. Therefore, the probability of occurrence of an accident or a malfunction of equipment important to safety, previously evaluated in the FSAR Update is not increased. The flooding analysis for the Auxiliary Saltwater system in the FSAR Update would envelope any failure of the temporary sensors. The removal of the thermowells does not increase the radiological consequences of any accident because it does not affect any radiological system. Also none of the instruments are required for normal operation or accident mitigation. Therefore, the consequences of an accident or a malfunction of equipment important to safety, previously evaluated in the FSAR Update is not increased. The existing and added temporary instrumentation do not affect the operation of components on either the Auxiliary Saltwater or the Component Cooling Water systems. Therefore, the possibility of an accident or a malfunction of equipment important to safety of a different type than any previously evaluated in the FSAR Update is not increased. The basis for the Technical Specifications associated with this change does not define any margin. Therefore, the margin of safety as defined in the basis for any Technical Specification is not increased.

DCL #	Page	Descriptions
	31	8. Temporary Modification, Plant Jumper: Installation of Test Equipment Jumper Log No. 91-XX (Unit 1) This jumper will install more accurate temperature and flow instruments on the inlet and outlet of the Component Cooling Water Heat Exchanger. Operational temperature instruments on the inlet and the outlet of the Component Cooling Water are replaced temporarily with more accurate instruments. Test flow D/P cells are connected across the existing operational flow D/P cell. The jumper is required to be in place to perform Temporary Procedure TB-9049 and will be removed prior to entry into operational Mode 4. Safety Evaluation Summary The temperature instruments are light in weight and meet the exclusion criteria of the SISI Manual. The flow D/P cells are valved out of the system except when in use. The new temperature instruments are installed in the existing thermowells so the design integrity of the system will be preserved and any leakage from the new flow D/P connections has been evaluated. Therefore, the possibility for an accident or malfunction of a different type than any evaluated previously in the FSAR Update is not created. The instruments replaced by the installation of this jumper are not described, defined, or used to monitor the Technical Specifications. Therefore, the margin of safety as defined in the basis for any Technical Specification is not reduced. The temperature instruments will be placed in existing thermowells, seismic concerns have been addressed; and, the existing leakage analysis will cover the new instrument installation. Therefore, the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the FSAR Update is not increased.
DCL-93-008	4	7. The IPE takes credit for (recovering) many long-term pressurization sequences. The probability of this recovery action is noted as 90 percent. What is the basis for this probability value? Does this probability apply to both CFCUs and sprays?

DCL #	Page	Descriptions
	13	PG&E Response As explained in Sections 4.8.2.3 and 4.8.2.5 of the IPE Report, containment failure for many of the sequences in the "Late Release" category is predicted by MAAP to occur in excess of 48 hours after event initiation. Most of these containment failures are due to loss of containment heat removal capability which is potentially recoverable. Many IPEs consider a Level 2 mission time of 48 hours or shorter from event initiation and do not consider containment failures that would happen after the mission time. The Zion Level 2 PRA (NUREG/CR-4551 Vol. 7, p. 2-7) states "Although ex-vessel interactions will progress for days, the end of this analysis was usually set at 24 hours (from core uncovery)." For the DCPP IPE, instead of using a mission time in the Level 2 PRA (as was used in Level 1), it was decided to use a more conservative approach, which was to assume a long-term containment heat removal recovery factor of 90 percent. Containment heat removal capability could be recovered if CCW, ASW, or electric power is recovered, depending on the sequence. Existing plant procedures direct operators to recover these systems in the event they are lost. The recovery factor of 90 percent is based on engineering judgment. As stated in Section 4.8.2.5, the judgment is based on the numerous means available to recover failed systems and the availability of personnel who would provide expert guidance to restore containment heat removal capability, given the very long duration (> 48 hours) before containment failure. This recovery factor is consistent with the 95 percent recovery factor used in Question 69 (recovery of containment heat removal capability) of the Zion Level 2 analysis (NUREG-4551, Volume 7, Revision 1). The probability assumes either recovery of CFCUs or containment sprays. 21. Since the assessment of core damage due to flooding is subject to much uncertainty in the parameters used in the assessment, please discuss your consideration of the sensitivity of the credit taken for operator action, address the flood scenarios that dropped below the core damage frequency screening criteria because the frequency has been reduced by more than an order of magnitude due to credit taken for operator action, and discuss how the application of the criteria you've chosen assures the capture of potential vulnerabilities due to flooding.

DCL #	Page	Descriptions
	15	PG&E Response A large number of actual industry-wide flooding events were reviewed and screened out if they were not applicable to DCPP or if the impact was insignificant. In general, no human actions were considered when screening out these industry flooding events; therefore, no flood scenarios were dropped due to credit taken for human action. However, human recovery credit was taken for one flood scenario - a flood in the CCW system due to pipe rupture, or CCW header leakage due to maintenance activities (FL1). The flooding scenario FL1 is treated identically to loss of CCW internal event transients except for the inclusion of one operator action with a relatively high failure rate (probability of operator failing to isolate the leaking CCW header). FL1 was not screened out and the scenario was analyzed in the plant model to determine its contribution to the core damage frequency. The sensitivity of FL1 to low operator failure rates was also assessed. Since only one operator action with a relatively high failure rate was added for flooding scenarios, it can be assured that our method of treating human actions in the flooding analysis will not exclude the capture of any potential vulnerabilities due to flooding. 25. The discussion under top event SE indicates that if top event PR fails (i.e. PORV opened & failed to reseat), the top event SE (RCP seal cooling) is not asked because a LOCA is then already known to have occurred. If seal cooling is lost subsequent to PR, is the resultant size of the LOCA from both leaks significant to success criteria, timing, CDF, and release category? PG&E Response The Level 1 event trees assume core damage is guaranteed (no chance of success) if a PORV fails to reseat (PR=F) and RCP seal cooling via the thermal barrier (CCW) is unavailable. Top event SE includes establishment of backup RCP seal cooling (Firewater hookup to the centrifugal charging pumps), but this human action is not applied for cases where a PORV fails to reseat. In the Level 1 event trees, the occurrence of PR failure and RCP seal cooling unavailability is treated conservatively - no chance of successful mitigation and core damage is guaranteed. Timing and release category have impacts only on the Level 2 PRA.

DCL #	Page	Descriptions
	21	In the back-end analysis, the cases of a failed open PORV compounded by a RCP Seal LOCA were not modeled using MAAP. Only single faults were considered: a fully stuck open PORV or one of the four types of RCP Seal LOCAs. To assess the impact of multiple leak paths, MAAP sensitivity studies were performed to address the effect of compounding a stuck open PORV with the various types of RCP Seal LOCAs. The potential impacts are on (1) timing of events and (2) potential release categories. 32. Please discuss any prevention or mitigation measures which address the significant contributors from those systems and/or actions that have been identified in Tables 3. 4.2- 1 through 3. 4. 2- 7. PG&E Response As part of the IPE process, the results of the DCPP IPE were reviewed by PG&E to determine any potential vulnerabilities, and to identify potential improvements at DCPP. The IPE Report documented in Sections 3.4.2.5 and 4.8 that there are no vulnerabilities at DCPP. Nevertheless, the more significant contributors to core damage were reviewed to determine if any design changes or procedure changes would reduce the more significant contributors to risk. Also, the conservatism involved in the PRA analyses was assessed to better understand the risk profile. The first contributor to core damage of significance is the RCP Seal LOCA. Over 40 percent of the CDF contribution includes RCP Seal LOCAs. RCP Seal LOCAs are postulated when cooling to the RCP seals is lost or is inadequate. Normally, RCP seal cooling is lost or is inadequate as a result of loss of electric power (full or partial station blackout), or as a result of loss of auxiliary saltwater or component cooling water. Even with the loss of component cooling water, RCP seal cooling can be maintained via a centrifugal charging pump (which normally requires CCW cooling) by aligning an alternate cooling water source (firewater) to the centrifugal charging

DCL #	Page	Descriptions
		pump. This ability was identified, implemented, and proceduralized as a result of the Diablo Canyon PRA. As part of the IPE process, improvements to the plant procedures OP AP-10, "Loss of Auxiliary Saltwater System," and OP AP-11, "Malfunction of Component Cooling Water System," were made to further reduce the likelihood of RCP Seal LOCAs, by enhancing the procedures on restoring CCW and ASW. Specifically, in OP AP-10, the procedure was modified such that in the event the unit's ASW system cannot be recovered, and ASW cross-tie to the opposite unit is not possible, the procedure now directs the operators to enter OP AP-11. OP AP-11 was modified so it now directs the operators to consider hooking up firewater cooling to a centrifugal charging pump in the event CCW temperatures are high and cannot be reduced. Prior to the IPE, the procedure only directed the operators to hook up firewater to the centrifugal charging pumps in the event that all of the CCW pumps failed to operate. The second significant contributor to core damage is the transient induced LOCA, occurring through a stuck open PORV. Many transient induced LOCAs occur after a Loss of Offsite Power event and typically involve failed diesel generators, making closure of the PORV block valves impossible without crosstying of vital buses. The PRA conservatively assumes all Loss of Offsite Power initiating events will result in a challenge to the PORVs. Additionally, only limited credit is provided for crosstie of vital buses to allow the PORV block valves to be closed. Thus, the transient induced LOCA contribution is conservatively evaluated. The addition of the sixth diesel generator will reduce the contribution of transient induced LOCAs, as explained in the following paragraph. Failure of diesel generators contribute significantly to core damage sequences, especially Loss of Offsite Power events. The addition of the sixth diesel generator scheduled for 1993 means each DCPP unit will have three dedicated diesel generators. Currently, one of the diesel generators is a "swing diesel." The addition of the sixth diesel is expected to reduce the overall contribution of the Loss of Offsite Power initiating events (from transient induced LOCAs or RCP seal LOCAs). It also will reduce the likelihood of RCP Seal LOCAs and transient induced LOCAs leading to core damage from other initiating events. As explained in Section 6.1, other design changes have already been implemented at Diablo Canyon as a result of the Diablo Canyon PRA, prior to performance of the IPE. The diesel fuel oil transfer system was modified to improve system reliability by eliminating multiple starts of the transfer pumps. A portable, engine-driven, fuel oil transfer pump was added as a backup. The ability to establish alternate cooling to the charging pumps (firewater) was added. Seismic changes included staging of substation spare parts.

DCL #	Page	Descriptions
		One final mitigation or prevention measure implemented as part of the IPE was to train DCPP personnel on PRA methods, insights, and applications. The PRA Group and the Training Department have conducted training sessions to introduce to DCPP operators and engineers the PRA methods, applications, and insights. Although the benefits are not easily quantified, this training is believed to have increased awareness and safety at DCPP.
DCL-93-038	LER	On January 13, 1993, with Units 1 and 2 in Mode 1 at 100 percent power, PG&E determined that under certain conditions and equipment configurations, the component cooling water (CCW) system water temperature design-basis limits may be exceeded. A one-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72 (b)(1)(ii)(B) on January 13, 1993, at 1053 PST. Prior to this event, analyses had been performed which demonstrated that the CCW system would remain within its design basis temperature limits. These analyses used nominal values for parameters that were judged not to have significant impact on the peak CCW temperature. Subsequently, more refined analyses have been performed using worst-case limits for such parameters rather than nominal values. The results of these analyses indicate that, under a combination of worst-case conditions and parameters, the CCW design temperature limits may be exceeded. The root cause for this event is under investigation and has not yet been determined. A supplemental LER will be issued by May 31, 1993, to report the root cause and corrective actions to prevent recurrence.
DCL-93-043	13	17. Replace the Component Cooling Water Potassium Chromate Corrosion Inhibitor DCP M-45469 Rev.0 (Units 1 and 2) The potassium chromate corrosion inhibitor for the Component Cooling Water (CCW) System was replaced with a molybdate-based inhibitor. This will reduce personnel hazards, simplify maintenance activities, reduce the amount of hazardous waste generated at DCPP, and eliminate the possibility of a chromate release to the environment.

DCL #	Page	Descriptions
	36	Safety Evaluation Summary Elimination of the chromate corrosion inhibitor will have no effect on the CCW system's ability to perform its design functions. The removal cannot affect the accident analyses. Some passive, nonsafety-related piping modifications outside the normal boundary of the CCW system were made to accomplish this chemical changeout. There is no possibility that this piping change would adversely affect system operation since administrative controls assured continuing system pressure boundary integrity during the short time used to change the inhibitor chemical. There are no concerns like water hammer, seismically induced systems interaction, and separation. There are no specific Regulatory Guides that apply to corrosion inhibitor water chemistry for the CCW system. The molybdate-based corrosion inhibitor is nonhazardous at operating concentrations and less toxic than chromate. Technical Specification 3.7.3.1 is not affected and the licensing basis is maintained. 3. Surveillance Test Procedure: Performance Test Of Component Cooling Water Pumps STP P-8A Rev. 8 (Units 1 and 2) The implementation of this procedure revision will collect Component Cooling Water(CCW) pump performance data at various flow points. Safety Evaluation Summary The system alignment required by the procedure revision protects against the failure to start or failure of the pump being tested by having the standby pump start on low header pressure. The procedure requires a pretest alignment of the pump suction and discharge valves per an operating procedure and the periodic check of the discharge check valves by a surveillance test procedure. Therefore, the probability of occurrence and the consequences of an accident previously evaluated in the FSAR update are not increased. During performance of the test, CCW flow to the system header associated with equipment important to safety is ensured by alignment of the pumps and heat exchangers. Therefore, the probability of occurrence and the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR Update are not increased.

DCL #	Page	Descriptions
		The CCW System is aligned differently during the performance of this test. However, the test alignment provides the same system redundancy as when the system is aligned for normal operations. A precaution of this test procedure requires monitoring the pump motor current to prevent the CCW pump from running out. Therefore, the possibility of an accident or a malfunction of equipment important to safety of a different type than previously evaluated in the FSAR Update is not created. Two vital CCW loops are operable during the performance of this test, and the system alignment during the test allows the "standby" pump to provide backup for either the "test" or "running" pump to meet the single failure requirement. Therefore, the performance of this test does not reduce the margin of safety as defined in the basis for any Technical Specification.
DCL-93-049		On January 13, 1993, with Units 1 and 2 in Mode 1 at 100 percent power, PG&E determined that under certain conditions and equipment configurations, the component cooling water (CCW) system water temperature design-basis limits may be exceeded. A one-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72 (b)(1)(ii)(B) on January 13, 1993, at 1053 PST. Prior to this event, analyses had been performed which demonstrated that the CCW system would remain within its design basis temperature limits. These analyses used nominal values for parameters that were judged not to have significant impact on the peak CCW temperature. Subsequently, more refined analyses have been performed using worst-case limits for such parameters rather than nominal values. The results of these analyses indicate that, under a combination of worst-case conditions and parameters, the CCW design temperature limits may be exceeded. The root cause for this event is under investigation and has not yet been determined. A supplemental LER will be issued by May 31, 1993, to report the root cause and corrective actions to prevent recurrence.
DCL-93-114	Attachment A	1. TS 3.3.3.5 is revised as follows: a. The TS title is changed from "Remote Shutdown Instrumentation" to "Remote Shutdown Instrumentation and Controls." b. The list of remote shutdown instrumentation in TS Table 33-9 is revised to include the following remote shutdowns control functions: auxiliary feedwater (AFW) flow control, charging pump control, component cooling water (CCW) pump control, auxiliary saltwater (ASW) pump control, and emergency diesel generator (EDG) control.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL-93-128		On November 4, 1992, Unit 1 entered Mode 4 (Hot Shutdown). TS 3.7.3.1 requires two CCW loops to be operable in Modes 1 through 4. TS 4.7.3.1.a requires that, at least once per 31 days, the position of containment valves not sealed in position be verified. On April 25, 1993, during reverification of the sealed valve checklist procedure, valves CCW-1-161 and 162 were identified to be open but not sealed. The root cause for this event was personnel error. The corrective actions for this event include issuing an Operations Incident Summary describing this event and revising procedures to verify accessible sealed valves within 31 days following a refueling outage.
DCL-93-290	LER	On November 19, 1993, with Units 1 and 2 in Mode 1 (Power Operation) at 100 percent power, PG&E determined that Technical Specification (TS) 2.6.2.3, Containment Cooling, was not met for both Units when all five containment fan cooling units (CFCU) were inoperable in Mode 4 (Hot Shutdown). Since initial plant startup, whenever either Units enters Mode 4 from Mode 3 (Hot Standby), both redisual heat removal (RHR) heat exchangers are placed in service to remove decay heat from the core. However, placing the RHR heat exchangers in service without throttling results in the component cooling water (CCW) flow to the CFCU cooling coils decreasing below that required by TS 4.6.2.3a.2) for operability. The root cause of this event is that the TS did not adequately incorporate plant design basis and operating configurations. A license amendment request (LAR) will be submitted to revise TS 3.6.2.3. Also, operating and surveillance procedures will be revised following issuance of the LAR. In addition, a review of the CCW and CFCU TS and procedures will be performed to ensure all design requirements are appropriately implemented in plant procedures. Also, PG&E QA Safety System Functional Audits and Reviews will be required to review TS against associated design requirements.
	Attachment A	This license amendment request (LAR) proposes to revise Technical Specification (TS) 3/4.6.2.3, "Containment Cooling System," and 3/4.3.2, "Engineered Safety Features Actuation System." TS 3.3.2, Table 3.3 3 and Table 4.3 2, Functional Units 2.c. and 3.b.3), would be revised to expand the mode applicability to Mode 4. The proposed changes to TS 3/4.6.2.3 would be as follows:

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL-94-004		1. TS 3.6.2.3. would be revised to require that at least four containment fan cooling units (CFCUs), or three CFCUs, each supplied by a separate vital bus, be operable. 2. Action statement a. would be revised to clarify the equipment required to be operable when in the action statement. 3. Action statement b. would be deleted. 4. Action statement c. would be renumbered to action statement b. and revised to clarify the equipment required to be operable when in the action statement. 5. TS 4.6.2.3a.2) would be revised to clarify the minimum component cooling water (CCW) flow to the CFCUs as 1650 gpm during normal operation which will assure that the required accident flow is satisfied. 6. A footnote would be added to the surveillance requirement of TS 4.6.2.3a.2) allowing all CFCUs to have low COW flow for ASME Section XI testing and Mode 4 operation with the residual heat removal (RHR) heat exchangers in service for decay heat removal. 7. TS 4.6.2.3a.3) would be revised to remove cycle specific information that is no longer applicable. The Bases for TS 3/4.6.2.3 would also be appropriately revised.
DCL-94-045	1	1. Revise Minimum Component Cooling Water Temperature DCP J-31642 Rev. 0 (Unit 1) and DCP J-32642 Rev. 0 (Unit 2) This setpoint change lowered the alarm setpoint from 75°F to 45°F for the component cooling water (CCW) heat exchanger outlet temperature to minimize nuisance alarms in the control room. The lower temperature limit is applied primarily to minimize the potential for condensation accumulation in the ECCS pump lube oil reservoirs. The oil in the charging pump and the safety injection pump reservoirs is tested for moisture on a regular basis to assure the absence of condensation. Safety Evaluation Summary This change lowered the alarm setpoint from 75°F to 45°F for the CCW heat exchanger outlet temperature. Temperatures under 75°F may promote condensation in the lube of! systems of the ECCS pumps. To replace this alarm function, periodic sampling of ECCS Frump lube oil is performed to detect unacceptable moisture content. The design evaluation for this change included concurrence from Westinghouse of a suggested surveillance interval that will maintain lube oil integrity within reasonable limits. With the additional surveillance in-place, an equivalent level of protection is provided. No accident or malfunction of equipment or its consequences are affected. The functionality, availability, and operability requirements of the ECCS equipment in Technical Specification Sections 3.1.2, 3.5.2, and 3.5.3, and their bases, are not affected by this change.

DCL #	Page	Descriptions
	25	27. Development of Component Cooling Water System Flow Balance Basis DCP M-47872 Rev. O (Units 1 and 2) No physical changes were made or required. Engineering analyses of the component cooling water (CCW) system were performed to develop information to aid the plant in balancing the system's flows to assure that actual cooling water flows to vital components are consistent with the performance assumptions and requirements of the system. Use of the flow balance information for operation of the facility will further ensure that assumptions embedded in the accident analyses of record are maintained. Safety Evaluation Summary Use of the developed flow balance information for operation of the CCW system will not increase either the consequences or the probability of occurrence of previously evaluated accidents. The CCW system is not the source or cause of any previously evaluated design/licensing-basis accidents, but is instead intended to provide support for mitigation of such accidents. The specific flow rates to vital equipment during accident conditions have been analyzed and shown to be adequate to maintain the 6377S -25- operating parameters within existing design basis assumptions. Furthermore, operation of the CCW system in accordance with this flow balance does not represent a change to any analysis assumption that is related to the initiation of an accident. Redundancy, reliability, and integrity of the CCW system are unaffected by operation in accordance with the established flow balance. Cooling water flow rates specified by the flow balance do not create additional stresses in the CCW system components, or the vital equipment it serves, that would make failure of any component more likely. In the event a malfunction of equipment previously in the FSAR Update should occur, operation of the CCW system in accordance with the flow balance will in no way increase the severity of the consequences of the malfunction. There are also no required system equipment or alignment changes associated with the balanced flow operation that could create a new type of accident or malfunction. No new failure modes need to be postulated, since there are no operational changes. The CCW flow rates associated with balanced flow operation of the system will ensure that minimum containment heat removal requirements are met. Analyses also show that the CCW system will not overheat due to excessive heat input from the containment fan cooling units (CFCUs) during an accident. Therefore, the margins of safety defined in the bases of the Technical Specification will not be reduced by balanced flow operation of the CCW system.

DCL #	Page	Descriptions
	44	2. Temporary Shielding Request: For Letdown Heat Exchanger TSR 92-047, Unit 1 This temporary lead shielding will be installed on the letdown heat exchanger. The shielding is required for ALARA concerns. The shielding will be installed in plant operating Mode 6. Safety Evaluation Summary The reactor coolant system (RCS) will be isolated from the heat exchanger and the component cooling water (CCW) system will remain operational during the time the temporary shielding is in place. The additional weight of the shielding has been evaluated for impact on the heat exchanger seismic qualification and the potential overstress of the heat exchanger or the concrete floor in the area. It was determined that the addition of the shielding will not adversely affect the heat exchanger, the concrete floor in the area of the heat exchanger, or the performance of the CCW system. A seismic induced systems interaction review of the shielding installation was performed and it was found that no new failure modes were created by the installation of the shielding. Therefore, it is concluded: 1. The probability or consequences of occurrence of an accident or a malfunction of equipment important to safety, previously evaluated in the FSAR Update are not increased. 2. The possibility of an accident or malfunction of equipment important to safety of a different type any already evaluated in the FSAR Update is not created. The addition of letdown heat exchanger shielding will not adversely affect the letdown heat exchanger, the CCW system, or the auxiliary building structure. Therefore, the margin of safety as defined in the basis of any Technical Specification is not reduced. 1. Surveillance Test Procedure 10 Year ISI Hydrostatic Test of CCW Supply and Return Headers A, B. and C and Associated Components STP X-310, Revision 0, Unit 1; STP X-310. Revision 0, Unit 2 Procedure STP X-310 is used to perform the 10 year ISI hydrostatic pressure test of vital CCW supply and return headers A and B. miscellaneous CCW supply and return header C, and associated components. The test is performed with the CCW system in normal service with the plant operating in Modes 5 or 6.

DCL #	Page	Descriptions
		Safety Evaluation Summary The plant will be in operating Mode 5 or 6. The CCW is not the source or cause of any of the previously evaluated accidents. None of the equipment malfunctions of previously evaluated in the FSAR Update is more likely to occur because the CCW system and components will be tested within their design pressure. The thermal performance of the CCW system is not adversely affected and all the functions required to support the safety function of the CCW system are maintained. Therefore,6377S -55-the probability of occurrence or the consequences of an accident or a malfunction of equipment important to safety previously evaluated in the FSAR Update are not increased. The performance of this test does not alter any existing accident analysis, create the need for a new analysis or affect system operation. No credible damage or failure can result from this test that will result in the loss of all function of the CCW system or any other important-to-safety equipment serviced by the CCW system. Therefore, the possibility of an accident or a malfunction of equipment important to safety of different type than any already evaluated in the FSAR Update is not created. The preparation for, the configuration for, and the performance of the hydra test will not cause the need to compromise the Technical Specification requirements for operability, continuing CCW system support for reactivity control and decay heat removal, and RCS fluid mixing capability. Therefore, the margin of safety as defined in the basis for any Technical Specification is not reduced.
DCL 94-046	1536	BASIS FOR REQUEST (Cont'd) Excess Letdown Heat Exchanger Girth Welds G-A, G-B This is a vertical vessel supported by steel 'feet' on concrete piers with pads welded to the shell closely abutting and restricting access to each subject weld. On the vessel shell, at 90 degrees to each support pad, the nozzle penetrations further limit access to these welds. The shell to flange weld cannot be scanned from the flange side due to flange configuration, and the head to shell weld is limited from the head side due to head curvature. Approximately 15% of weld G-A is accessible from the shell side. Approximately 10% of weld G-B is accessible from the shell side.

DCL #	Page	Descriptions
	1540	RHR Heat Exchanger 1-1, 1-2 Girth Welds G-A, G-D and Nozzle Welds N-1, N-2 This is a vertical vessel supported in the same manner as the excess letdown heat exchanger. The head to shell and shell to flange welds (G-A and G-D) are restricted to approximately 15% and 10% due to the support pads, nozzles, flange and head curvature. The nozzle welds are restricted by the adjacent support pads, by the flange, and by the curvature of the head underneath. Approximately 10% of each nozzle weld is accessible from the shell side. They are not accessible from the nozzle side due to the nozzle geometry. RHR Heat Exchanger Shell and Nozzle Welds - Surface examination approximately 80% each (limited by vessel supports). Volumetric examination to the extent practical (approximately 10% of welds G-D, N-1, and N-2 and 15% of weld G-A).
DCL 94 049	LER	On December 30, 1993, at 1150 PST, with Unit 1 in Mode 3 (Hot Standby) at 0 percent power and Unit 2 in Mode 1 (Power Operation) at 100 percent power, PG&E determined that the auxiliary saltwater (ASW) system and its associated component cooling water (CCW) heat exchangers for both units may not have met their design basis for certain time periods prior to implementation of continuous chlorination. Continuous chlorination was fully implemented in September and November 1992 for Units 1 and 2, respectively. This condition was reported to the NRC as a one hour, non emergency report in accordance with 10 CFR 50.72 (b)(1)(ii)(B) at 1150 PST on December 30, 1993. The cause of this condition was an inadequate understanding of the effects of fouling on the CCW heat exchangers. The ASW systems for both units currently are operable given the present maintenance, operational, and testing activities. These activities assure that the ASW system will remain sufficiently clean such that fouling will not prevent the system from performing its design basis functions. CCW heat exchanger tests on both units will be performed to provide additional confirmation of the adequacy of operational and maintenance practices to assure that the CCW heat exchangers meet their design basis requirements. An equipment control guideline was implemented to ensure compensating actions are taken if the ASW chlorination system becomes inoperable.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL 94-120	LER	On December 30, 1993, at 1150 PST, with Unit 1 in Mode 3 (Hot Standby) at 0 percent power and Unit 2 in Mode 1 (Power Operation) at 100 percent power, PG&E determined that the auxiliary saltwater (ASW) system and its associated component cooling water (CCW) heat exchangers for both units may not have met their design basis for certain time periods prior to implementation of continuous chlorination. Continuous chlorination was fully implemented in September and November 1992 for Units 1 and 2, respectively. This condition was reported to the NRC as a one-hour, non-emergency report in accordance with 10 CFR 50.72 (b)(1)(ii)(B) at 1150 PST on December 30, 1993. The cause of this condition was an inadequate understanding of the effects of fouling on the CCW heat exchangers. The ASW systems for both units currently are operable given the present maintenance, operational, and testing activities. These activities assure that the ASW system will remain sufficiently clean such that fouling will not prevent the system from performing its design basis functions. CCW heat exchanger tests on both units will be performed to provide additional confirmation of the adequacy of operational and maintenance practices to assure that the CCW heat exchangers meet their design basis requirements. An equipment control guideline was implemented to ensure compensating actions are taken if the ASW chlorination system becomes inoperable.
DCL 94-174	1	NRC Enforcement Action 94-056, dated July 14, 1994, contained a Notice of Violation that cited one Severity Level III violation. The violation involved the failure of PG&E's engineering staff to promptly identify and correct issues that arose as a result of tests performed in 1991 to determine whether the Component Cooling Water Heat Exchanger 1-2 had the ability to remove the design basis heat load. The root cause of the violation was determined to be inadequate attention to engineering practices that should have ensured clear definition of test acceptance criteria for the heat exchanger testing prior to the test being performed and a failure to comprehensively resolve the negative test results in a timely manner. Specific concern was expressed about PG&E's failure to take advantage of several opportunities, particularly our own Quality Assurance organization's self identification of the deficiency in mid 1993, to thoroughly resolve the issue prior to the NRC's inspection in late 1993. As discussed in DCL-94-037, dated February 15, 1994, and DCL-94-049, dated March 8, 1994, PG&E conducted a comprehensive evaluation of these concerns and has taken extensive corrective actions to address them. The commitments made in these previous responses constitute the corrective actions we have taken or intend to take. PG&E believes that its previous Generic Letter (GL) 89-13 program, combined with these additional corrective actions, provide assurance that the ASW system is fully operable and capable of meeting its design basis. Recent testing and inspection activities confirm the effectiveness of these actions.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL-94-208	LER	On January 13, 1993, with Units 1 and 2 in Mode 1 at 100 percent power, PG&E determined that, under a combination of worst-case conditions and parameters, the component cooling water (CCW) system water temperature design-basis temperature limits may be exceeded. A one-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72 (b)(1)(ii)(B) on January 13, 1993, at 1053 PST. The root cause of this event was nonconservatisms in the design-basis analysis for the CCW system. The design records do not contain sufficient information to conclude whether the root cause of this event was an error, an oversight, or that it was the judgment of the engineer that the effect on the conclusions of the analysis were insignificant. Surveillance Test Procedure V-13A, "CCW Flow Balancing," was revised to implement the CCW flow balancing calculations. Also, STP M-51, "Routine Surveillance Test of Containment Fan Cooler Units," was revised to assure the flow balance requirements are verified during routine testing to demonstrate compliance with the Technical Specifications.
DCL-94-157	LER	On June 24, 1994, with both Units 1 and 2 in Mode 1 (Power Operation) at 100 percent power, PG&E determined that throttled component cooling water (CCW) flow to the centrifugal charging pump (CCP) skid was not sufficient to meet specified CCP skid subcomponent flow rates; therefore, design basis requirements for post-LOCA CCP operation may not have been met. As a result, a 1-hour, non-emergency notification was made to the NRC on June 24, 1994, at 1739 PDT in accordance with 10 CFR 50.72(b)(1)(ii)(B). During an investigation of the auxiliary saltwater and CCW system design basis as part of the actions for LER 1-93-012, "Auxiliary Saltwater System Outside Design Basis Due to Fouling," a discrepancy was identified between the Westinghouse design basis flow to the CCP skid and design calculations used to establish acceptability of the throttling practice for cooling water to the coolers. The throttle valves on each CCP cooler skid were fully opened and sealed in position pending further investigation. A test was performed on June 24 to determine actual CCW flow to the CCP skid subcomponents under throttled conditions. The test demonstrated CCW flow that did not meet specified skid subcomponent flow rates. Following testing, the valves were returned to full-open conditions pending determination of long-term corrective actions. An operability assessment has been performed which shows that unthrottled flows to the CCP skid are acceptable. The root cause of this event is under investigation and will be reported in a supplement to this LER in conjunction with any other corrective actions.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL-95-121	LER	On June 24, 1994, at 1700 PDT, with both Units 1 and 2 in Mode 1 (Power Operation) at 100 percent power, PG&E determined that the throttled component cooling water (CCW) flow rate to the centrifugal charging pump (CCP) skids may not have been high enough to adequately cool the CCP skid subcomponent heat exchangers and, therefore, maintain post-accident CCP operability. As a result, a 1 hour, non-emergency notification was made to the NRC on June 24, 1994, at 1739 PDT in accordance with 10 CFR 50.72(b)(1)(ii)(B). The CCP skid throttle valves were opened to the full-open position. A test was developed and performed to determine actual CCW flow rates to the CCP skid subcomponents under throttled conditions. CCP skid flow balancing was performed to determine optimum flow conditions. Following testing, the valves were returned to the full-open position pending determination of the final valve throttling position. The cause of throttling of CCW flow to the CCPs was human error, inadequate understanding of design basis. Corrective actions include calculation revisions and establishment of a method to control flow to the CCP skid such that each subcomponent heat exchanger receives sufficient flow to perform its design basis function.
DCL-95-135	3	4. Installation of Corrosion Monitoring System in the Component Cooling Water System DCP M-47029 Rev. 0, Unit 1 and DCP M-48029 Rev. 0, Unit 2 This change provided for corrosion monitoring of the Component Cooling Water (CCW) System. The corrosion monitoring system consists of a corrosion test loop installed between two taps in the system. The test loop consists of four coupon locations and two spare connections for future use. This design change provides the capability to monitor the effectiveness of the molybdate-based CCW corrosion inhibitor. The data provide a quantitative measure of the actual corrosion rates in the safety-related CCW System.

DCL #	Page	Descriptions
		Safety Evaluation Summary The corrosion monitoring system test loop that has been added to the CCW System is seismically qualified to maintain the CCW System pressure boundary and to avoid interaction with surrounding equipment. The monitoring system does not change the CCW System characteristics nor affect the performance or functions of the CCW System. The CCW System does not contribute to the initiation of an accident, and this design change does not affect how the CCW System responds following an accident. Therefore, this design change does not increase the probability or the consequences of any accident previously evaluated in the FSAR Update. The test loop contains a Class I strainer that will prevent any loose coupons, screws, or nuts from entering the CCW headers. The pressure retaining portion of the coupon holder is seismically qualified. The test loop does not affect the performance of the CCW System and the design change did not create any interactions with other safety-related systems. Therefore, there is no effect on any malfunction of equipment important to safety previously evaluated is the FSAR Update. The addition of the corrosion test loop does not create different accidents or malfunctions. Any parts in the test loops that could become loose are trapped by a qualified strainer. Failure of the isolation valves in the test loop would not have an impact on the safety function of the CCW System. There are no electrical devices associated with the test loop. Since the design change does not change any functions or the performance of the CCW System, there is no change in the margin of safety provided by this system.
	27	1. Test Equipment Installation For Component Cooling Water Heat Exchanger Performance Test, Unit 2 To run a performance test on the Unit 2 component cooling water (CCW) heat exchangers, the following temporary plant modifications were made. The auxiliary saltwater (ASW) inlet temperature local indicators were removed and replaced with test RTDs, and the outlet temperature local indicators with their thermowells were removed and replaced with specially designed test RTDs. These temporary modifications also installed □P transmitters across the ASW vents and drains of both CCW heat exchangers.

DCL #	Page	Descriptions
	35	The temporary modification to the CCW side of heat exchangers removed the inlet temperature element and the outlet local temperature indicator for each heat exchanger and replaced them with test RTDs. The temporary modifications also installed flow transmitters in parallel with the permanently installed flow transmitters for the "A," "B," and "C" CCW vital headers. Since the local temperature indicators were removed to install the test equipment, it was necessary to read the temperatures from the data logger located in the heat exchanger room. The installed test equipment was small when compared to the size of the CCW heat exchangers and, therefore, meet the seismically induced system interaction exclusion criteria 3.4.14. D. Tests and Experiments 1. Surveillance Test Procedure: Component Cooling Water Flow Balancing STP V-13A Rev. 0, Units 1 and 2 Surveillance Test Procedure: Routine Surveillance Test of Containment Fan Cooler Units STP M-51 Rev. 15, Unit 1 and STP M-51 Rev. 4, Unit 2 Surveillance Test Procedure (STP) V-13A was written to change the flow balance using the throttle valves at the component cooling water (CCW) discharge from the containment fan cooler unit (CFCU). The procedure was written to establish a CFCU flow balance that will result in CCW flow to the CFCU coils within the allowable flow range during the design basis accident of greater than 2000 gpm and less than 2500 gpm. STP M-51 was revised to incorporate the effects of CCW flow balance in accordance with STP V-13A. This ensures that the CCW design basis temperature limit is not exceeded, thus meeting the intent of the CFCU function as described in the TS Bases.
DCL-95-156	1	As part of an effort to eliminate microbiological growth and corrosion deposits in several of the closed cooling water systems at PG&E's Diablo Canyon Power Plant (DCPP), PG&E is proposing a short-term program to remove existing growth and associated surface deposits and a long-term chemical control program to minimize future growth and deposits within the systems. The following is a description of these two programs. We have determined that implementation of these programs will not significantly change the character of the discharge from the plant.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL-96-052	D-84	This Technical Specification (TS) change would add TS 4.7.3.1c to verify start of each component cooling water (CCW) pump start as follows: TS 4.7.3.1c, regarding verification that each CCW pump starts automatically on an actual or simulated actuation signal, would be added with a surveillance frequency of at least once each REFUELING INTERVAL. The proposed addition is provided in the marked-up copy of TS page 3/4 7-11 in Attachment B. The proposed new TS page is provided in Attachment C. The surveillance, maintenance, and operating history of the CCW pump automatic actuation circuitry support the conclusion that the effect on safety from extending the fuel cycle is small. Surveillance testing of the start circuitry has been in place since initial plant operation. PG&E believes that adding the start verification to the TS with a surveillance frequency of at least once per refueling interval is conservative and will not adversely affect the health and safety of the public.
DCL-97-010	Enclosure 2, Page 1	DESIGN CRITERIA The ASW system design criteria is to supply sufficient cooling water to the CCW HXs to support normal operation and mitigate design basis accidents without exceeding the CCW design basis temperature limits. LICENSING BASIS The ASW system licensing basis requirement is to provide sufficient flow to the CCW HXs to ensure that the maximum CCW temperature does not exceed 120°F with a one time allowable transient to 132°F for 20 minutes. CONCLUSIONS The design and licensing basis requirements of the ASW system will continue to be met. In addition, the calculation demonstrates that the ability of the ASW system to pass STP M-26 will not be affected.

DCL #	Page	Descriptions
DCL-97-013	3	4. Replace Motor Operators on Certain Valves from Rotork Motor Operators to Limitorque Motor Operators DCP J-047195 Rev. 1 (Unit 1) DCP J-048195 Rev. 0 (Unit 2) This design change specifies a different manufacturer to procure spare parts. Certain valves in the auxiliary saltwater (ASW) system and CCW system which had Rotork motor operators will be replaced with Limitorque motor operators since spare parts are no longer available from Rotork. Some valves will be changed to manual valves since their design purpose was to isolate pipes for maintenance purposes. For a majority of the valves (those that are covered by TS or other design requirements), the design requirements such as stroke times are still maintained. In some cases, the previously specified stroke times are changed. However, these valves are not covered by any TS requirements, and the new stroke times have been evaluated to meet the system design requirements. Convert the Mechanical Seals on Centrifugal Charging Pump 1-2 from First Generation to Third Generation Mechanical Seals DCP N-049201 Rev. 1 (Unit 1) The Centrifugal Charging Pump 1-2 casing was replaced with a stainless steel casing as a prudent measure to prevent deterioration of the casing. This replacement stainless steel casing has been converted to accommodate the third generation mechanical seals. This change allows the use of the third generation seal that is an improved design that provides for a longer service life. Since the new seal does not require CCW for cooling, this design change also allows capping of CCW lines that are used to provide cooling water to the pump seals and the removal of the seal coolers from the pump skid. Safety Evaluation Summary The new third generation mechanical seal meets or exceeds the original mechanical seal requirement; however, external cooling is not required. Capping of the CCW piping has negligible effect on the CCW system since the flow rate through the seal coolers is very small compared to the total CCW system flow. Although the heat load from the seal coolers is very low, a small margin is gained from eliminating the cooling water requirement for the seals. Seal life is extended as a result of the one-piece seal sleeve/pumping ring design. Therefore, the availability of the centrifugal pump is increased. Also, because CCW is no longer required for cooling, one of the failure modes that can cause This design change is an improvement to the existing component. These modifications do not affect the charging pump and CCW system function, performance, or operability. Also, no new equipment is added and no new failure mode has been introduced.

DCL #	Page	Descriptions
	9	14. Rerate the Residual Heat Removal Heat Exchangers and Pumps to a Higher Design Pressure DCP N-049118 Rev. 0 (Units 1 & 2) The residual heat removal (RHR) system pressure is determined by the RCS pressure at the RHR pump suction plus the RHR pump differential pressure. Throttling the RHR pump flow increases the pump discharge head. When this pressure increase was added to the maximum pressure at the pump suction, it caused the pressure at the RHR heat exchangers and RHR pumps to exceed their design pressures. This change rerates the design pressure of the RHR heat exchangers and the RHR pump to a higher design pressure and provides for flexibility in operating the RHR system while meeting the Code requirement for design pressure. Safety Evaluation Summary The design pressures of the RHR pumps and RHR heat exchangers are increased by refining the required stress analysis to accommodate the possible increase in maximum operating pressure that can occur by throttling of the RHR pumps. The equipment still complies with the applicable Code requirements by reducing certain conservatisms used in the original analysis and using the material properties of existing equipment. This is a document change only. Since there is no physical change to either the RHR pumps or the RHR heat exchangers, there is no increase in the probability or consequences of any FSAR Update evaluated malfunctions. The system will continue to be operated within design pressures. Since there is no physical work associated with this DCP, no different types of accidents or malfunctions are created by this change, and the change has no impact on the margin of safety as defined in the basis for any TS.
	17	27. Pressurization of the Component Cooling Water Surge Tank DCP M-049284 Rev. 0 (Unit 1) DCP M-050284 Rev. 0 (Unit 2) Due to the potential for the CCW fluid to flash inside the CFCUs during a large break LOCA coincident with a loss of offsite power, the CCW surge tank was pressurized to 17 psig (nominal) to increase the static head on the system. The modification uses plant nitrogen as the primary source of pressure, with a Design Class I backup pressure source from nitrogen bottles with redundant regulators. An additional backup pressure supply is also provided by plant instrument air. The existing surge tank vent, RCV-16, which closes in the event of radioactive inleakage to the tank, will remain intact, with a downstream backpressure regulator.

DCL #	Page	Descriptions
	25	5. Service Cooling Water Heat Exchanger Cooling - Firewater Supply Jumper #96-08 (Unit 2) The normal cooling for the service cooling water (SCW) heat exchanger is provided by the salt water system. During the Unit 2 seventh refueling outage, both the circulating water pumps were secured for maintenance and testing. This required an alternate cooling supply for the SCW heat exchanger. This cooling supply was provided by the fire water system. The supply was connected through a regulator to lower the water pressure from 89 psig to 40 psig. Safety Evaluation Summary The SCW heat exchanger is normally provided cooling water supply by the salt water system as described in the FSAR Update. The jumper provided an alternate cooling supply from the firewater system during the refueling outage. This cooling enabled the SCW heat exchanger to perform its intended function for Modes 5 and 6. The 90 psig fire water supply pressure is well within the SCW heat exchanger design pressure. The installation was seismically installed and there was no impact of the jumper on the operating requirements of the SCW or the firewater systems. The firewater system was evaluated to (1) ensure its capability to supply the cooling flow while still providing fire protection capabilities, and (2) ensure its integrity for the possible failure modes of the jumper configuration. Potential turbine building flooding issues were also addressed. The jumper had no impact on any safety parameter and there was no reduction in the margin of safety as defined in the basis for any Technical Specifications.

DCL #	Page	Descriptions
	33	3. Surveillance Test Procedure: Flow Balancing Component Cooling Water to Equipment on the Centrifugal Charging Pump Skid STP PEP M-200 Rev. 0 (Units 1 & 2) This test procedure installs and removes ultrasonic flow meters that have been calibrated by Technical and Ecological Services to allow testing of the component cooling water (CCW) flow to the individual components on centrifugal charging pump (CCP) pump skids. The test can be performed in any mode provided the RHR heat exchangers are not in service. The test measures flows to the equipment and adjusts the flows to meet minimum design requirements. Safety Evaluation Summary This test procedure allows for engineering control of the valves that affect the flow balance of CCW to the CCP skid equipment. This ensures that CCW flow is maintained within required limits to the CCP skid components important to safety. Therefore, this procedure does not affect the accident analysis, the type of accident previously evaluated, the malfunction of equipment important to safety, or the safety margin.
	33	4. Surveillance Test Procedure: Determination of Recirculation Flow through the Centrifugal Charging Pump Miniflow Orifice STP PEP M-222 Rev. 0 (Units 1 & 2) This test procedure determines CCP recirculation orifice flow capacity during normal charging and correlates that flow capacity to post-LOCA conditions. If the orifice flow capacity is found to be excessive, the valve downstream of the recirculation orifice is throttled to lower the orifice flow to prevent the CCP from exceeding the allowable total pump flow, while maintaining the required minimum flow.

DCL #	Page	Descriptions
	34	6. Surveillance Test Procedure: Residual Heat Removal Heat Exchanger 1-1 Performance Test STP PEP M-238 Rev. 0 (Unit 1) This test procedure installs and removes test instruments that allow testing of the heat transfer capability of the RHR heat exchanger. The test is typically performed during a plant cooldown in Mode 4 and it measures RHR and CCW flows into the RHR 1-1 heat exchanger. It also measures temperatures in and out of both RHR and CCW sides of the RHR 1-1 heat exchanger. The results are used to evaluate the condition of the CCW system regarding microbiological fouling/blockage concerns. Safety Evaluation Summary In Mode 4, which is when this test is performed, one RHR train or one reactor coolant system loop is required to be operating. This test is performed with both RHR trains operating but separated by closing RHR-1-8726A. The alignment of the “A” train of RHR in this test by closing RHR-1-8726A isolates this train from the heat exchanger bypass loop, but this does not affect the design basis for any analyzed accidents, nor does it change the probability of occurrence of any analyzed accident since it does not restrict either train of RHR from operating or from injecting into all four cold legs. The alignment of the “A” train of RHR in this test does not prevent the RHR system from performing its intended design basis function. The only possible consequence is the possibility of exceeding the allowable cooldown rate during shutdown cooling. The cooldown rate is controlled by operator action to throttle the flow through both heat exchangers and through the bypass loop for the “B” RHR train. The Technical Specification basis for the RHR system in Mode 4 is that only one operable ECCS subsystem is required. This basis is not affected by this test procedure; therefore, there is no reduction in the margin of safety.
	36	8. Temporary Procedure: Feed and Bleed of the Component Cooling Water System TP TB-9512 Rev. 0 (Unit 1) This temporary procedure proposes an activity to feed and bleed the CCW system to reduce chemical concentrations in the CCW coolant. It utilizes installed system components in conjunction with a temporary drain line to drain CCW coolant out the plant discharge via the ASW discharge line. Makeup to the system is provided via the normal source using a manually controlled valve.

DCL #	Page	Descriptions
		During feed and bleed, the level in the CCW surge tank is maintained in the normal operating range and automatic level control is not affected. Discharge flow is within the makeup capability of the makeup water system. An operator is stationed at the discharge flow control and isolation valves to immediately isolate discharge flow in the event of a low CCW surge tank level due to loss of makeup flow, system leak, or an emergency. Operators are directed to immediately secure discharge of CCW overboard if any indication of a primary coolant leak into the CCW system is detected. Operators are also directed to secure CCW discharge flow to the ASW system if ASW flow is lost to prevent any build up of CCW coolant on the ASW side of the heat exchanger. A check valve is placed in the temporary drain line to preclude seawater backflow into the CCW system.
	41	2. Component Cooling Water Surge Tank Pressurization System ECG 14.1 Rev. 1 The component cooling water (CCW) surge tank pressurization system provides pressure on the CCW surge tank to maintain CCW pressure above the post-LOCA saturation pressure in the containment fan cooler unit coils. This precludes the possibility of CCW flashing and subsequent water hammer during the design basis LOCA, even if double sequencing occurs. Therefore, the purpose of the ECG revision is to provide administrative controls to ensure that the CCW pressurization system and the CCW system are capable of performing their required functions.
	47	11. Auxiliary Saltwater System and Component Cooling Water System Analysis Section 9.2 and Associated Figures This revision documents the effect of a revised analysis (in Appendix 6.2C) on the auxiliary saltwater and component cooling water (CCW) systems. The change involves the methodology used to determine the consequences associated with FSAR Update accident analyses, including the effects of malfunction of equipment important to safety. The new LOCA analysis predicts higher CCW temperatures in the post-LOCA recirculation phase due to higher sump water temperatures. This condition has been analyzed and actions have been taken to ensure that the CCW system will support the required equipment to mitigate a design basis LOCA. Compliance with the accident success criteria is maintained, and no unreviewed safety question exists.

DCL #	Page	Descriptions
DCL 97-013	17	27. Pressurization of the Component Cooling Water Surge Tank DCP M-049284 Rev. 0 (Unit 1) DCP M-050284 Rev. 0 (Unit 2) Due to the potential for the CCW fluid to flash inside the CFCUs during a large break LOCA coincident with a loss of offsite power, the CCW surge tank was pressurized to 17 psig (nominal) to increase the static head on the system. The modification uses plant nitrogen as the primary source of pressure, with a Design Class I backup pressure source from nitrogen bottles with redundant regulators. An additional backup pressure supply is also provided by plant instrument air. The existing surge tank vent, RCV-16, which closes in the event of radioactive inleakage to the tank, will remain intact, with a downstream backpressure regulator. Safety Evaluation Summary The modification meets all CCW system design requirements. The safety function of the compressed gas is to maintain CCW system pressure at or above 17 psig for the first minute of the accident. Since the compressed gas maintains the surge tank pressure before a design basis accident, the components added by this modification have no active safety function to perform once the accident has occurred. The safety function of the new components is to maintain pressure boundary integrity. As noted in the FSAR Update, the failure of these components is not postulated for the first 24 hours following a LOCA. All components used to pressurize the surge tank are seismically qualified and installed and meet the piping and instrumentation codes and standards for a Design Class I system. The use of nitrogen to pressurize the tank will not cause any adverse effect on CCW chemistry or heat transfer capability since it is an inert gas. Although nitrogen is the preferred gas for the surge tank pressurization, compressed air can be used as a pressurization source. No adverse effects are postulated with the use of compressed air since the surge tank was previously open to atmosphere. Based on these design aspects, the safety evaluation concluded that no unreviewed safety question existed.

DCL #	Page	Descriptions
	23	2. Component Cooling Water Surge Tank - Removal of Relief Valve RV-45 and Functional Bypass of RCV-16 Jumper #95-14 (Unit 1) Relief Valve RV-45 was removed to perform an inspection of the component cooling water surge tank to check for foam and signs of biofouling. This condition rendered RCV-16 ineffective for isolating the surge tank in the event of the release of any radiological material. The jumper permitted bypassing of the function of RCV-16 to close on a high radiation signal while Relief Valve RV 45 was removed and the tank was open to atmosphere. Safety Evaluation Summary The function of RCV-16 is to close on a high radiation signal. Since this function was bypassed, in the event of a high radiation alarm, the control room has an annunciator alarm. In addition, there is also an alarm for high surge tank level. This would allow time for the source of the inleakage to be identified and isolated before a large quantity of water leaks onto the roof. Also, the manual valve CCW-1-89 upstream of RCV-16 will be opened and any discharge can be routed to an appropriate drain to minimize the potential for an uncontrolled release. There was no impact on the margin of safety due to the removal of RV 45 since there are no Technical Specifications (TS) or Equipment Control Guidelines associated with the function of the relief valve.
	36	8. Temporary Procedure: Feed and Bleed of the Component Cooling Water System TP TB-9512 Rev. 0 (Unit 1) This temporary procedure proposes an activity to feed and bleed the CCW system to reduce chemical concentrations in the CCW coolant. It utilizes installed system components in conjunction with a temporary drain line to drain CCW coolant out the plant discharge via the ASW discharge line. Makeup to the system is provided via the normal source using a manually controlled valve. During feed and bleed, the level in the CCW surge tank is maintained in the normal operating range and automatic level control is not affected. Discharge flow is within the makeup capability of the makeup water system. An operator is stationed at the discharge flow control and isolation valves to immediately isolate discharge flow in the event of a low CCW surge tank level due to loss of makeup flow, system leak, or an emergency. Operators are directed to immediately secure discharge of CCW overboard if any indication of a primary coolant leak into the CCW system is detected. Operators are also directed to secure CCW discharge flow to the ASW system if ASW flow is lost to prevent any build up of CCW coolant on the ASW side of the heat exchanger. A check valve is placed in the temporary drain line to preclude seawater backflow into the CCW system.

DCL #	Page	Descriptions
	41	Safety Evaluation Summary The feed and bleed of the CCW system, along with the associated precautions and limitations, provide adequate assurance that safe CCW and ASW system operation will not be impacted. The length of time the system is left with dilute corrosion control inhibitors until chemicals are added to reestablish chemical concentration to effective levels is minimized. This results in continued operation of both the CCW and ASW systems at their regular effectiveness with no degradation of the margin of safety. 2. Component Cooling Water Surge Tank Pressurization System ECG 14.1 Rev. 1 The component cooling water (CCW) surge tank pressurization system provides pressure on the CCW surge tank to maintain CCW pressure above the post-LOCA saturation pressure in the containment fan cooler unit coils. This precludes the possibility of CCW flashing and subsequent water hammer during the design basis LOCA, even if double sequencing occurs. Therefore, the purpose of the ECG revision is to provide administrative controls to ensure that the CCW pressurization system and the CCW system are capable of performing their required functions. Safety Evaluation Summary The proposed changes to the ECG would not affect the probability of occurrence of an accident. Compliance with Technical Specification 3.0.3 and an orderly unit shutdown, if needed, is an expected evolution for the Diablo Canyon units. The loss of the CCW pressurization system could render the CCW system inoperable only if double sequencing were to occur. However, double sequencing occurring with a LOCA is not considered part of the Diablo Canyon licensing basis. Thus, a 7-day allowed outage time is reasonable if only the CCW pressurization system is inoperable. Double sequencing, however, should be considered during the times when the 230-kV system is known to be degraded (as defined by System Operations Instruction O-23). If the 230-kV system were degraded at the initiation of an event, double sequencing would occur. If the CCW pressurization system were inoperable, the CCW system integrity would be challenged as a result of flashing in the CFCU coils during the resulting double sequencing.

DCL #	Page	Descriptions
		Consistent with the requirements of Technical Specification 3.0.3, the plant should be placed in a safe condition if a safety function, such as the operability of the CCW system, cannot be satisfied. The ECG requires that Technical Specification 3.0.3 be entered for the CCW system if the 230-kV system were degraded and the CCW pressurization system were inoperable. If the possibility of double sequencing were eliminated, the CCW system would perform its required function regardless of the operability of the pressurization system. Therefore, an allowance to exit Technical Specification 3.0.3 upon restoring the 230-kV system, the CCW pressurization system, or preventing double sequencing by opening the 4-kV vital bus transfer to startup cutout switches ensures that the CCW system will be capable of performing its required function. Therefore, the consequences of an accident previously evaluated are not increased. Degraded 230-kV system voltage and the potential for double sequencing is another LOCA scenario where CCW flashing could occur. While the required design basis of the plant only requires consideration of a complete loss of offsite power coincident with the LOCA, the ECG appropriately includes an action statement to declare both trains of CCW inoperable (and enter TS 3.0.3) if both the CCW pressurization system and the 230-kV system are known to be degraded. The ECG provided administrative controls that ensure availability of the pressurization system to maintain the ability of the CCW system to accommodate a design basis LOCA, with double sequencing. Although short durations of system unavailability are allowed under the ECG allowed outage time, the CCW system remains capable of performing its design function under the re-evaluated LOCA coincident with loss of offsite power conditions. Under the conditions of a degraded 230-kV system, the ability of the CCW system to accommodate a LOCA and double sequencing cannot be demonstrated. As a result, with the CCW pressurization system out of service and the 230-kV system in a degraded condition, Technical Specification 3.0.3 restrictions will be applied to the CCW system. Under the described conditions, the margin of safety as defined in the basis for any Technical Specification will be maintained.
DCL-97-018	82	(c) CCW flow balance issues. The assurance that adequate flow was available to ESF components during accident conditions could not be determined since neither procedural guidance nor adequate indication was provided to allow flow balance of the CCW system (Audit 90811T, Ref. 2.10). Engineering provided input regarding flow requirements, and an STP was developed to verify flow balancing once each outage (Ref. 5.46).

DCL #	Page	Descriptions
		(d) Performance test results for CCW heat exchanger 1-2 predicted a heat removal capability less than the design basis value assumed in the accident analyses (Surveillance QP&A-93-0031, Ref. 2.39). Heat exchanger performance tests were reperformed with more accurate instrumentation, and the performance was acceptable. PG&E determined that there may have been times when the design basis requirements were not met, and issued a one-hour report pursuant to 10 CFR 50.72. The root cause was that design basis requirements were not adequately incorporated into test acceptance criteria. Corrective actions included revisions to calculations, the DCM, STPs, and an administrative procedure; and issuance of a new administrative procedure and an ECG (Ref. 5.47).
	84	(4) The licensee discovered tube fretting damage at baffle plate locations in both of the redundant Unit 2 CCW heat exchangers tubes in March 1993. (NRC Inspection Report 93-34, Ref. 3.30) Tube plugging was completed where necessary, and an operating procedure was changed (Ref. 5.51).
DCL-97-036	LER	On January 31, 1997, at 1130 PST, with Units 1 and 2 in Mode 1 (Power Operation) at 100 percent power, PG&E determined that the component cooling water (CCW) and auxiliary saltwater (ASW) systems have operated with procedural guidance that permitted, following a loss of coolant accident and the loss of power on either Vital Bus F or G, operation in a condition outside the design basis of the plant. A 1-hour, non-emergency report was made to the NRC at 1220 PST, in accordance with 10 CFR 50.72 (b)(1)(ii)(B). The cause of the event is unknown, but it occurred during the original design of the plant. The cause is attributed to incomplete or incorrect application of the single failure criteria design requirement to ASW and CCW systems operation during post-accident split train, hot leg recirculation. Emergency Operating Procedure E-1.4, “Transfer To Hot Leg Recirculation,” has been revised to no longer require immediate separation of the ASW and CCW systems into separate trains after the transfer to hot leg recirculation. The decision to separate has been transferred to the Technical Support Center, where a decision will be made after an evaluation of plant conditions. This action precludes placing the plant into a configuration where this vulnerability would be created without a thorough assessment being performed.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL-97-046	3	PG&E installed a nitrogen pressurization system on the CCW system (CCWS) in May 1996 to provide positive pressure to assure that the CCWS water will not flash to steam during the time that the CCWS pumps are de-energized during transfer of the vital busses to the emergency diesel generators. The CCWS nitrogen pressurization system is currently controlled under administrative plant controls. Recent evaluations of the CCWS nitrogen pressurization system have concluded that the system should be included in the Technical Specifications (TS). A license amendment request is under development to add minimum pressure requirements for the CCW system to the TS and is expected to be submitted to the NRC in March 1997.
DCL-97-074	2	A. DESCRIPTION OF AMENDMENT REQUEST This license amendment request (LAR) proposes to change Technical Specification (TS) 3/4.7.3.1 as follows: 1. New action statements will be added to TS 3.7.3.1 to address inoperability of the component cooling water (CCW) surge tank pressurization system. 2. New CCW surge tank pressurization system surveillance requirements will be added to TS 4.7.3.1. The associated TS Bases will be appropriately revised. The proposed changes are provided in the marked up copies of the TS pages in Attachment B. The proposed new TS pages are provided in Attachment C. C. JUSTIFICATION Implementation of CCW surge tank pressurization system TS would ensure that the CCWS is maintained within its original design and licensing basis. CONCLUSION The CCW surge tank pressurization system has been added to ensure that the CCWS is capable of performing its design basis function following a double guillotine LOCA with a concurrent LOOP. PG&E has demonstrated that, for a limited displacement pipe break LOCA concurrent with a LOOP, the CCWS remains capable of performing its design basis function without the CCW surge tank pressurization system. A PRA of both licensing and non-licensing basis (non-concurrent LOOP) scenarios has conservatively established an AOT of 12 hours consistent with an “acceptable” risk increase equal to 1.0E-07 as suggested by EPRI methodology. An AOT of 12 hours should allow sufficient time to restore the CCW surge tank pressurization system to operable status while minimizing the period of operation without the system. If the CCW surge tank pressurization system becomes inoperable with the 230 kV system degraded, the plant would be shutdown within one hour unless the pressurization system is returned to service or the electrical system is reconfigured to prevent double sequencing.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL-97-083	Attahment A, Page 1	The change to Technical Specification (TS) Bases 3/4.7.3, “Vital Component Cooling Water,” and 3/4.7.12, “Ultimate Heat Sink,” increased the maximum temperature at which the component cooling water (CCW) system may operate after a design basis event from 132□F for 20 minutes to 140□F for six hours after the event, returning to a maximum of 120□F thereafter. This revision reflects upgraded qualifications of CCW components and equipment cooled by CCW to show that they can function with the higher temperature cooling water. An administrative change to relocate the temperature limit from Bases 3/4.7.12 to Bases 3/4.7.3 was also made to improve consistency.
	2	1. CCW System: CCW return temperatures corresponding to the increased 140□F CCW supply temperature were determined based on conservative post-accident CCW heat input criteria that were intended to envelope current accident analyses. Bounding conditions included the use of highest instantaneous containment vapor space temperature, highest instantaneous containment sump temperature, lowest CCW flows to cooled components, and highest projected containment fan cooler unit (CFCU) and RHR heat exchanger heat transfer rates considering conservative fouling factors and with CCW supply at 140□F. The calculation determined that the maximum CCW return temperature from an individual component was 241□F, from the CFCUs during the post-accident injection phase. For the cold-leg recirculation phase of the post-accident response, the return temperature from the CFCUs was 227□F. Return temperatures for other components and return headers are lower than 241□F. The maximum temperature, 241□F, was found to be acceptable because equipment is qualified to handle that temperature and flashing will not occur at the highest point in the CCW system, the top of the CFCUs, or at the downstream side of the CFCU throttle valves, assuming the minimum allowable CCW flow through the CFCUs. The impact of the new CCW temperatures on the CCW piping system and pipe support system has been evaluated. Piping specifications for CCW readily accommodate the increased temperature qualification. The impact of pipe support load changes on the structure has been evaluated and found to be acceptable, as documented in the appropriate civil/structural calculations. The impact of this design change on the CCW pump suction head requirement (NPSH) was evaluated and found to be acceptable. Calculations established the acceptability of CCW pump NPSH up to CCW temperatures of 250□F, in the CCW flow ranges required for post-accident response.

DCL #	Page	Descriptions
	3	The impact of this design change on CCW surge tank liquid level was evaluated and found to be acceptable. Calculations considered thermal expansion of the CCW liquid volume under conditions that bound the calculated post-accident temperature increase and insurge rate. The impact of the increased CCW temperatures on mechanical equipment within the CCW pressure boundary was evaluated. The evaluation demonstrated the functionality and structural integrity (including nozzle loads, equipment support loads, and seismic qualification) of vital equipment at the increased CCW temperatures, and the assurance of pressure boundary integrity and seismic support, as required, for nonvital equipment at the increased CCW temperatures. 2. CCW Cooled Equipment: Functionality requirements include minimum required CCW flow rates that must be achieved to qualify the associated equipment for the new increased CCW post-accident temperature qualification. The minimum required CCW flow rates that must be achieved to qualify the associated vital equipment for the new increased CCW post-accident temperature qualification are within the calculated flows as determined in the most limiting CCW flow balance calculations. Major system/equipment evaluations are summarized below: • RHR System: The impact of the increased CCW supply temperature on the RHR pump, including its seal coolers and accompanying piping and skid assembly, has been evaluated by the vendor and found to be acceptable. It was necessary to rerate the RHR heat exchanger shell side from a design temperature of 200□F to an increased design temperature of 250□F to accommodate the increased CCW post-accident temperatures. As owner, PG&E can perform a rerating of the RHR heat exchangers in accordance with ASME Section XI, “Rules For Inservice Inspection of Nuclear Power Plant Components.” The rerating was accomplished through reanalysis by the vendor, who has evaluated the design of the RHR heat exchangers for the new design temperature in accordance with design code (ASME Section VIII, 1968 edition) requirements, and has accepted revised RHR heat exchanger nozzle loads resulting from associated piping reanalysis performed by PG&E. Considering only the design temperature increase, the heat exchanger allowable stresses and applicable loadings do not change as a result of this uprating.

DCL #	Page	Descriptions
	7	The existing qualification of the RHR return piping from the RHR heat exchangers was reviewed and found to be acceptable because temperatures considered in the associated analyses bound the conditions imposed by the increased CCW temperature qualification. Summary Based on the above evaluations it is concluded that the CCW system, its support systems, and the equipment cooled by CCW will function properly under normal operating and all postulated accident conditions. This change, which increases allowable post-accident CCW temperatures, involves changes from the design as described in the FSAR Update, and therefore requires the performance of a 10 CFR 50.59 safety evaluation. E. 10 CFR 50.59 SAFETY EVALUATION 1. May the probability of occurrence of an accident previously evaluated in the Safety Analysis Report (SAR) be increased? The component cooling water (CCW) system is not a precursor to any accident evaluated in the SAR. There is no effect on systems supported by CCW during normal plant operation due to this change; any potential increase to CCW temperatures would only be experienced after an accident has occurred. Normal operating CCW temperature and initial conditions for accident analyses remain unchanged. Therefore, there is no increase in the probability of occurrence of any accident previously evaluated in the SAR.

DCL #	Page	Descriptions
	7	2. May the consequences of an accident previously evaluated in the SAR be increased? This change upgrades qualifications for equipment to verify that the equipment will remain operable with higher CCW water temperature, and does not revise accident analyses. The increased CCW temperature qualification only provides for an increase in the allowable post-accident CCW temperature response, and thereby an increase in the heat storage capacity of the CCW following an accident. All CCW components, support components, and components cooled by CCW will continue to perform their intended accident mitigation functions following a design basis event. Therefore, the consequences of an accident previously evaluated in the SAR are not increased.
	8	3. May the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the SAR be increased? This change does not modify any equipment or system operating procedures in either the normal or emergency modes, except to establish a minimum valve position for CCW heat exchanger auxiliary salt water (ASW) discharge throttle valves, SW-1/2-65 and SW-1/2-66, for cavitation mitigation. These valves are normally throttled already, and the required minimum valve position imposed by this change is within the range of the current normal operation of these valves. The imposition of these valve position requirements serves to minimize potential cavitation effects and has no detrimental impact on the capability of the ASW to perform its normal and emergency functions. Based on detailed evaluations of all affected systems, components, and structures, it has been demonstrated that they will perform their intended safety functions with the increased CCW water temperature conditions. Therefore, this change does not increase the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the SAR.

DCL #	Page	Descriptions
	8	4. May the consequences of a malfunction of equipment important to safety previously evaluated in the SAR be increased? The CCW system and interfacing systems have been qualified to meet the requirements of an increased CCW supply temperature of up to 140□F for up to six hours in post-accident operation. The increased temperature qualification provides for an increase in the allowable post-accident CCW temperature response, and thereby an increase in the heat storage capacity of the CCW in post-accident response. The ability of the CCW to support recovery from a malfunction of equipment (CCW system, support equipment, or cooled equipment) will thereby be increased. Therefore, the consequences of a malfunction of equipment important to safety previously evaluated in the SAR will not be increased.
	8	5. May the possibility of an accident of a different type than any previously evaluated in the SAR be created? This change requalified the CCW system, support systems, and systems cooled by CCW to increase the allowable post-accident temperature response of the CCW to existing accident analyses. There is no change to the method of operation of the CCW system. The change included no modifications to plant equipment beyond minor adjustments to valve positions to mitigate possible cavitation effects and resetting a post-accident sampling system (PASS) temperature switch to accommodate the new temperature. No new failure modes have been introduced. Therefore, the possibility of an accident of a different type than any previously evaluated in the SAR has not been created.

DCL #	Page	Descriptions
	9	6. May the possibility of a malfunction of equipment important to safety of a different type than any previously evaluated in the SAR be created? This change requalified the CCW system, support systems, and supported systems to increase the allowable post-accident temperature response of the CCW to existing accident analyses. Through documented engineering analysis and review it has been demonstrated that all affected systems, structures, and components will perform their intended safety functions at the increased temperature conditions. The change includes no modifications to plant equipment beyond minor adjustments to valve positions to mitigate possible cavitation effects and resetting a PASS temperature switch to accommodate the new temperature. No new failure modes have been introduced. Therefore, the possibility of a malfunction of equipment important to safety of a different type than any previously evaluated in the SAR has not been created.
	9	7. Is there a reduction in the margin of safety as defined in the basis for any technical specification? The criterion for acceptance for the maximum CCW supply temperature was, and continues to be, the maximum CCW supply temperature for which functionality of all required vital components is assured, based on equipment vendor requirements and qualification. The numerical value associated with this acceptance criterion has changed, as determined by the vendors through the same processes that established the previous numerical value associated with this acceptance criterion, without detrimental impact to operability of affected equipment. Based on these determinations, the numerical value associated with the acceptance criterion has changed from 132□F for up to 20 minutes to 140□F for up to six hours, with 120□F thereafter in both cases. Therefore, there is no reduction in the margin of safety as defined in the basis for any technical specification.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL-97-108		PG&E is submitting the enclosed licensing basis impact evaluation (LBIE), including a 10 CFR 50.59 safety evaluation, for installation of the component cooling water (CCW) surge tank pressurization system on Unit 1. Since the LBIEs for both units are almost identical, the LBIE for Unit 2 is not enclosed; both were approved by the Plant Staff Review Committee on April 15, 1996. The CCW surge tank pressurization systems for both units are controlled by an equipment control guideline. In License Amendment Request 97-05 (ref. PG&E letter DCL-97-074 dated May 22, 1997), PG&E proposed placing these systems under the control of technical specifications.
DCL 97-150	36	Per Mechanical Calculation M-988, the increase in head loss for bypass piping is not significant; the design basis flow is maintained with a margin and there is no significant effect on the Component Cooling Water (CCW) heat removal capacity.
DCL-97-151	1	PG&E has reviewed it's decision to install the CCW surge tank pressurization system under the 10 CFR 50.59 process. In part, 10 CFR 50.59 states that changes shall be deemed to involve an unreviewed safety question (USQ) if the probability of occurrence of a malfunction, or the consequences of a malfunction of equipment important to safety previously evaluated in the SAR may be increased. In regards to the malfunction issues, the CCW surge tank pressurization system is designed to mitigate the consequences of an accident, and cannot initiate an accident. Therefore it cannot increase the probability of a malfunction previously evaluated in the SAR. Failure of the CCW surge tank pressurization system does not involve a new malfunction in that the pressurization system would fail and cause depressurization of the surge tank. This is because the safety function of the system is to maintain surge tank pressure only for the first minute of a design basis loss-of-coolant accident (LOCA) with concurrent loss-of-offsite power. The system is designed to maintain CCW surge tank pressure before the LOCA occurs, and the components added by the system installation have no active safety function to perform once the accident has occurred. The only safety-related function of the components of the system is to maintain pressure boundary integrity. The non mechanistic failure of these components is not postulated within the first 24 hours following a LOCA. A calculation was performed as part of the DCP that verified, based on the surge tank low pressure alarm setpoint, instrument uncertainty, tank leakage as verified by surveillance test, and other conservative system parameters, that the surge tank would remain pressurized greater than 17 psig during the first minute of the accident, even if the pressure supply regulator were to fail closed. Since the failure of the surge tank is non mechanistic and pressurization of the tank does not introduce a mechanistic failure mechanism, a new malfunction is not introduced.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL-97-151		In regards to the consequences of an accident or malfunction being increased, PG&E concluded there would be no increase in consequences. The modification would not impact the heat transfer capability of the CCW system to provide cooling to safety-related components during accident conditions. Also the compensatory measures that were established during system installation maintained CCW system operability and compliance with licensing requirements. Therefore, under the criteria of the 10 CFR 50.59 process, PG&E came to the conclusion that installation of the system did not involve a USQ. PG&E continues to believe this to be true for the following reasons: 1. The design of the DCPP CCW system is not unique. The design and function of the DCPP CCW system is similar to reactor auxiliary cooling water systems installed in other light water reactor power plants. Consequently, it does not involve new design review issues. 2. Installation of the pressurization system is consistent with NUREG 0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition,” dated July 1981, Section 9.2.2, “Reactor Auxiliary Cooling Water Systems.” 3. Installation of the pressurization system is consistent with the DCPP licensing bases including Final Safety Analysis Report Update, Section 9.2.2, “Component Cooling Water System,” and Supplemental Safety Evaluation Report No. 16, dated August 1983.
DCL-98-007	2	2. IFI 50-275/97-202-02: Review of Revision to WCAP-14282 and incorporation of revised WCAP-14282 into design bases documentation (Section E1.2.1.2.c.2) Item Description - At the time of the inspection, WCAP-14282 was in revision to finalize the preliminary analysis done in PGE-96-503 and to also capture the history and the effect of the CCW system changes on all interfacing systems. Issue of the revised WCAP-14282 will also supersede/revise a number of calculations and design documentation including DCMs and the UFSAR. The changes necessary to incorporate revised WCAP-14282 into design bases documentation is being tracked by DCPP under AR A0439116.

DCL #	Page	Descriptions
		Response - WCAP-14282, Revision 1, was issued on December 12, 1997. WCAP-14282, Revision 1, will be incorporated into the DCPP design basis by DCP M-49386 which is currently in preparation. In conjunction with incorporating the results of WCAP-14282 into the design basis, DCP M-49386 will implement changes to the Final Safety Analysis Report Update (UFSAR), as well as various design criteria memoranda (DCMs), procedures and calculations relating to CCW/ASW system operation. As discussed above, DCP M-49386 will be implemented by June 1, 1998. The unique nature of the cooling systems and their limitations, and the need to update these analyses and associated documentation were recognized before the inspection, and have been addressed. No further generic considerations are required.
	3	3. URI 50-275/97-202-03: Determine if Long-term post-LOCA Operation of ASW System With Both Trains Tied Together Represents a USQ (Section E1.2.1.2.d) Item Description - The team reviewed the ability of the ASW system to be separated into two redundant trains for long term post-LOCA cooling as described in UFSAR section 9.2.7.2, and as was the intent of the original design. The team determined that the ASW system, in combination with CCW system, could withstand a single active failure during all phases of accident mitigation as long as the trains remained mechanically cross-tied. The ASW system is currently configured to operate with both trains tied together. DCPP EOP E-1.4, "Transfer to Hot Leg Recirculation," originally required separation of the ASW and the CCW systems into isolated trains approximately 10 1/2 hours after the LOCA. The EOP was revised as part of LER 97-001-00 corrective action and the trains are now separated during long term cooling based on a decision to be made by the TSC to separate the trains to be able to withstand a single passive failure in the fluid system. The team determined that this ASW system operation did not form the original bases for the ASW system design or licensing, and was a potential unreviewed safety question (USQ) that needed to be further evaluated by the NRC. Response - In early 1997, prior to the NRC Design Inspection, PG&E identified that realigning the ASW/CCW system into two separate trains created a vulnerability to a single active failure of an electrical power supply. This concern was addressed in Nonconformance Report (NCR) N0002010 and reported to the NRC in License Event Report (LER) 1-97-001-00.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
		The licensing basis impact evaluation (LBIE) performed to address the changes to the UFSAR and EOP was reviewed at the time of the NRC Design Inspection. PG&E continues to believe that the LBIE and attached safety evaluation conform to DCPP procedural requirements, and correctly conclude that these changes do not constitute an unreviewed safety question (USQ). PG&E will be working with Nuclear Reactor Regulation and Region IV to expeditiously resolve the USQ issue.
DCL 97-150	15 16	D. 2. AUXILIARY SALTWATER FLOW REDUCTION EVALUATION COMPARISON TO PREVIOUS DESIGN The ASW bypass project changed the routing and increase the length of the ASW supply piping. This change will increase the pressure drop in this piping and will reduce the flow of ASW to the CCW HX by approximately 352 gpm, approximately 3 percent. DESIGN CRITERIA The ASW system design criteria is to supply sufficient cooling water to the CCW HXs to support normal operation and mitigate design basis accidents without exceeding the CCW design basis temperature limits. LICENSING BASIS The ASW system licensing basis requirement is to provide sufficient flow to the CCW HXs to ensure that the maximum CCW temperature does not exceed 120°F with a one time allowable transient to 140°F for 6 hours.
DCL 98-044	Attachment A	This license amendment request (LAR) requests NRC review and approval of changes in how passive failures in the auxiliary saltwater (ASW) and component cooling water (CCW) systems are mitigated during the long-term recovery period following a loss-of-coolant accident (LOCA). The Final Safety Analysis Report (FSAR) requires that Diablo Canyon Power Plant (DCPP) be capable of tolerating a single active or passive failure without the loss of safety function. Prior to this change, protection from a passive failure in the ASW and CCW systems was ensured by splitting each of these systems into two separate cooling trains. In the split train configuration, however, a single active failure of an emergency diesel generator (EDG) could result in the loss of containment heat removal. To address this, the plant procedures have been revised such that train separation of the ASW and CCW systems after the transfer to hot leg recirculation following a LOCA is not required. The decision to separate the trains would be made by the Technical Support Center (TSC) after evaluation of plant conditions.

DCL #	Page	Descriptions
		The recommended configuration for the CCW trains is to be separated and for the ASW trains to remain crosstied. In this configuration, DCPP can mitigate a single active or passive failure without the loss of safety function. Alternate configurations are acceptable, but would require operator action to mitigate the effects of a single failure. These operator actions are consistent with the previously approved actions required to separate the ASW and CCW trains. Specific changes to the FSAR reflecting these changes in operation are shown on the attached FSAR pages 9.2-6, 9.2-11, 9.2 25, and Table 9.2-7. These changes were included in FSAR Update, Revision 11A, submitted to the NRC on April 30, 1997 (PG&E Letter DCL-97-075). The changes in plant operation provide maximum flexibility for responding to either an active or passive failure during the long-term recovery period following the accident, while maintaining the ability of the ASW and CCW systems to perform their safety function. Required operator actions are similar to other operator actions specified in the FSAR that are considered acceptable by the NRC. Also, the changes do not conflict with regulatory guidance, or the WOG emergency response guidelines for transfer to hot recirculation. Therefore, PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the changes in plant operation.
DCL-98-096	2	NRC Staff Request No. 1 “Before we can proceed with our review of this proposed change request, you must submit for our review and approval a complete description of the modifications that were made to the CCW systems. The information must be sufficient to enable the staff to perform an independent review of the modifications that were made, and should include (for example) system operating parameters, failure modes and effects analysis, all assumptions, and a one-line diagram depicting the components of the surge tank pressurization system.”

DCL #	Page	Descriptions
		PG&E Response: Enclosed is DCP M-049284 that was used for installing the CCW surge tank pressurization system on Unit 1. The Unit 1 and Unit 2 DCPs are almost identical so only the Unit 1 DCP is enclosed. The DCPs for both units were approved by the Plant Staff Review Committee on April 15, 1996. The DCP includes a design change evaluation (DCE), a licensing basis impact evaluation (including a 10 CFR 50.59 SE), markups of design criteria memoranda, and Final Safety Analysis Report (FSAR) sections. The DCE and supporting calculations for the DCP contain (1) system operating parameters, (2) a failure modes and effects analysis, and (3) all design assumptions. DCP Attachment I, page 11 of 12, contains a one line diagram of the pressurization system. Refer to the following attachments for the requested information: Attachment B DCP M-049284 for Unit 1 Attachment C Selected DCP Supporting Mechanical and Nuclear Calculations
	3	NRC Staff Request No. 2 "You previously stated that the surge tank is sized to allow sufficient time for operators to respond to a leak in the CCW system, assuming a 200 gpm leak rate over a 20 minute period. Because increased pressure in the CCW system will result in an increased leak rate over what was originally assumed, you are requested to discuss in detail what new leak rate will be assumed for this scenario and how the time allowed for operator response will be affected by this change." PG&E Response: The DCPP licensing basis leak rate for the CCW system is defined in the FSAR Update Section 9.2.2.3.3, "Makeup Provisions," and in Safety Evaluation Report Supplement (SSER) 16, Section 9.3.2.2, "Evaluation," dated August 1983, as a nonmechanistic leak of 200 gpm which provides operators with 20 minutes to locate and stop the leak. Since the assumed break was non mechanistic, a break size, or location was never identified. Since no break size or location was identified, it is not possible to determine a revised break flow rate with the system pressurized. PG&E did not assume a new leak rate for the CCW system with a pressurized surge tank. FSAR Update Section 9.2.2.3.3 states: "The CCWS has been designed to accommodate a non-mechanistic leak of 200 gpm. The CCWS surge tank volume provides operators with 20 minutes to locate and stop the leak, or realign the CCWS into two separate trains before the system operation becomes impaired due to water loss."

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
		SSER 16 discusses the results of the NRC staff's re-review of the CCW system against the general design criteria discussed in the Standard Review Plan (SRP), NUREG-0800, Revision 2, dated July 1981, Section 9.2.2, "Reactor Auxiliary Cooling Water Systems." The SRP did not exist at the time of the NRC staff's original review. SRP 9.2.2 states that moderate leakage cracks are determined in accordance with the guidelines of Branch Technical Position (BTP) ASB 3-1, "Protection Against Postulated Failures in Fluid Systems Outside Containment." BTP ASB 3-1 postulates through-wall leakage cracks in piping and branch runs exceeding a nominal pipe size of 1 inch, where the crack opening is assumed as 1/2 the pipe diameter in length and 1/2 the pipe wall thickness in width.
DCL-98-130	1	1. Final Safety Analysis Report, Section 6.2.2.2.2.1, specified that during the , recirculation phase of the accident, recirculation spray suction is provided by the residual heat removal pumps, which draw suction from the containment sump. The Final Safety Analysis Report, Section 6.2.3.2.1, identified that the mode of containment spray will continue for at least 2 hours following the accident. Technical Specification 3.6.2.1, "Containment Spray System," required two containment spray systems be operable with each spray system capable of taking suction from the refueling water storage tank and transferring the spray function to a residual heat removal system taking suction from the containment sump. in essence changed the technical specifications incorporated in the license. Specifically, the Emergency Operating Procedure E-1.3, "Transfer to Cold Leg Recirculation," Revisions 9 and 3 for Units 1 and 2, respectively, were revised delete starting a second residual heat removal pump if two auxiliary saltwater pumps and two component cooling water heat exchangers were not in operation. With only one residual heat removal pump in operation, the system was not to be placed in the containment spray recirculation mode. The safety evaluation performed in February 1992 did not identify that the technical specification requirement may not be met for containment spray recirculation with only one operating residual heat removal pump. A subsequent safety analysis completed on September 4, 1997, downgraded the containment spray in the recirculation mode of the emergency core cooling as nonsafety-related but did not address the technical specification requirement for containment recirculation spray.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
DCL-98-130	2	Section 9.2.2.2.7 of the Final Safety Analysis Report Update, stated that no local boiling would take place in the containment fan cooler unit coils during accident conditions. Contrary to the above, the safety evaluation for the Unit 1 and Unit 2 component cooling water nitrogen pressurization system Design Change Packages M-049284 and M-050284, included in the licensee's submittal dated June 12, 1997 (DCL-97-108), was inadequate to provide the basis for the determination that the proposed change did not involve an unreviewed safety question or a change in the technical specifications incorporated in the license. Specifically, the licensing basis impact determination for the modifications, installed in April and May 1996 for Units 1 and 2, respectively, did not appropriately consider whether the modification introduced vulnerabilities that were not previously considered in the system design. These included the impact of dissolved nitrogen on component cooling water pump net-positive suction head and the potential of vapor binding of the pumps, the effect of dissolved nitrogen on thermal conductivity, equipment malfunctions and single failure considerations, and the potential for increasing the consequences of an accident during installation of the modification. The failure to appropriately consider the nitrogen pressurization system impact on the technical specifications, which had been installed to ensure the component cooling water system would operate within its design basis, resulted in nonconservative technical specifications, in that, there was no action statement or surveillance requirement for the component cooling water surge tank pressurization system.
	3	REASON FOR THE VIOLATION A.2 PG&E agrees with the violation as stated in the IR. As discussed in a supplement to LAR 97-05, “Revision of Technical Specification 3/4.7.3,” submitted in DCL-98-096, dated July 9, 1998, the 10 CFR 50.59 safety evaluation, for the most part, presented only the summary conclusions of the safety evaluation process. The supporting details were contained in the associated design change package (DCP). As requested by the NRC, the supplement to LAR 97-05 contained Attachment B which provided a copy of DCP M-050284, Revision 0, “Installation of CCW Surge Tank Pressurization System for Unit 1,” for NRC review.

DCL #	Page	Descriptions
		In 1996, after reviewing the requirements of the NRC's "Final Policy Statement on TS Improvements," PG&E initially decided to place the component cooling water (CCW) pressurization system under the control of the equipment control guidelines instead of the TS because CCW system operability could be shown without having to rely on the surge tank (reference Licensee Event Report 1-96-005-01, "Potential for Flashing in Containment Fan Cooler Units," submitted in DCL-96-159, dated July 31, 1996). However, the CCW modification was required to support licensing bases assumptions for a design basis LOCA. Consequently, LAR 97-05 was submitted in DCL-97-074, dated May 22, 1997, and proposed TS changes as described as in the letter.
DCL-98-136	A-24	42. Requalification of the CCWS for a Maximum CCW Post-Accident Supply Temperature of 140□F DCP M-049291, Rev. 1 (Units 1 & 2) (LBIE Log No. 97-158) DCP M-049291, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-077) This design change package (DCP) established a new postaccident temperature limit profile for the component cooling water system (CCWS). This was achieved by upgrading individual components' temperature qualifications where necessary and revising the associated design and licensing documentation. This DCP was performed to document previously unrecognized margin between the postaccident CCW supply temperature profile and the documented CCWS equipment temperature limitations.
	A-25	45. CCW-1-TCV-130 Replacement (HOT TAP) DCP M049319 (Units 1 & 2) (LBIE Log No. 97-089) See LBIE 97-046 (Procedure MP I-38-M.1, Units 1 & 2, Rev.0 in "Procedures" section of report). This was a revision to LBIE Log No. 97-046 that changed the mode that work could be conducted. The mode was change from 0 to Modes 5, 6, or 0.
	A-26	47. Revised Peak CCW Temperature Following a Design Basis Accident DCP M-049386, (Units 1 & 2) (LBIE Log No. 98-070) The limiting component cooling water (CCW) temperature transients following a design basis accident (DBA) have been reevaluated by Westinghouse in WCAP 14282, Revision 1, dated December 1997. Revised WCAP-14282 captures previous CCW heatup evaluations contained in several documents and incorporates the latest design input while using the same methodology used in past analyses.

DCL #	Page	Descriptions
	A-27	49. Convert CCP 1-1 to 3rd Generation Seal Configuration DCP N-049231, Rev. 0 (Unit 1) (LBIE Log No. 96-016) The DCP changed/replaced the pump case and internal assembly for Centrifugal Charging Pump (CCP) 1-1 with a like-for-like pump case and internal assembly that has been equipped with the 3rd generation seal configuration. The old seal design (first generation) was a multicomponent assembly requiring external cooling by CCW. Although no known problem is associated with maintenance at DCPP for the 1st generation seals, the conversion to 3rd generation was done as an enhancement, which could increase pump availability.
	B-7	12. Operation of the Component Cooling Water (CCW) System to Support Replacement of Temperature Control Valve (TCV)-130 TP T0-9705, Rev. 0 (Unit 1) (LBIE Log No. 97-088) This temporary procedure was prepared to support replacement of CCW temperature control valve TCV-130. Due to a leaking return isolation valve, leak tight isolation of the line was not possible. To replace TCV-130, restriction orifice RO-239 had to be replaced with a blank plate so the bypass line would pass flow. It was necessary to establish a bleed path downstream of RO-239 to relieve pressure on the orifice so that its flange could be disassembled and the blank plate installed. New bypass isolation valves were added using a hot tap procedure that was also used to establish the bleed path. This procedure provided instructions to establish the bleed path from the CCW system and regulate makeup flow during the activities associated with RO-209.
	C-6	12. Reactor Trip or Safety Injection EOP E-0, Rev. 19 (Unit 1) (LBIE Log No. 97-025) Emergency Operating Procedure (EOP) E-0 was modified to add an instruction to place two component cooling water (CCW) heat exchangers in service if the reactor coolant system (RCS) is not intact at step 21 as preparation to transfer to EOP E 1.3. An item was also added to the foldout page to transition to EOP E 1.3 if the refueling water storage tank (RWST) level is less than 33 percent. The changes were made to reduce the operator response time to EOP E-1.3 when aligning the RCS for cold leg recirculation. The specific location of the instruction was chosen to ensure that it would be performed (i.e., not bypassed due to RNO on other steps), and to minimize potential disruptions in the flow of diagnosing and responding to the accident in progress.

DCL #	Page	Descriptions
	C-8	14. Reactor Trip or Safety Injection EOP E-0, Rev. 10 (Unit 2) (LBIE Log No. 97-026) Emergency Operating Procedure (EOP) E-0, “Reactor Trip or Safety Injection” was revised to include an action to place two component cooling water (CCW) heat exchangers in service if it is determined that the reactor cooling system (RCS) is not intact and a transition to EOP E-1, “Loss of Reactor or Secondary Coolant,” is required. Placing both CCW heat exchangers in service is done in anticipation of an eventual transition to EOP E-1.3. Placing this action in EOP E 0 is advantageous as it removes the operation from the timeline of cold leg recirculation alignment. Also, the foldout page was revised to instruct the operators to go to EOP E-1.3 immediately if the refueling water storage tank (RWST) level is less than 33 percent.
	C-14	19. Transfer to Hot Leg Recirculation EOP E-1.4, Rev. 11 (Unit 1) (LBIE Log No. 97-005) This procedure revision removes the requirement for auxiliary saltwater (ASW) train separation. A requirement was added to contact the Technical Support Center (TSC) for an evaluation of train separation and component cooling water (CCW) train separation, contingent upon TSC direction to do so.
	C-14	20. Transfer to Hot Leg Recirculation EOP E-1.4, Rev. 4 (Unit 2) (LBIE Log No. 97-006) Emergency Operating Procedure (EOP) 1.4 was revised so that component cooling water (CCW) and auxiliary saltwater (ASW) train separations are not required following transfer to hot leg recirculation. With both systems aligned to separate trains as required by the previous EOP revision, there was a concern that a postulated of loss of Bus F power would cause loss of containment heat removal due to loss of flow in one train and loss of ASW flow to the other CCW train. The procedure change allows realignment of ASW and CCW into separate trains to be performed after transfer to hot leg recirculation as directed by the Technical Support Center.

DCL #	Page	Descriptions
	C-18	26. Makeup Water Sources to the CCW System OP F-2:VII, Rev. 1 (Unit 1) (LBIE Log No. 97-131) Instructions were added to the operating procedure to use the firewater storage tank (FWST) contents to supply the component cooling water (CCW) system if needed. The use of the FWST for CCW makeup is described in FSAR Update Section 9.2.2.3.3. Prior to this revision, such usage was not addressed in an operating procedure. Safety Evaluation Summary The procedure change does not affect the status of any plant system prior to an accident. The FWST is used for CCW makeup only after failure of the CCW system and several other makeup sources. The specific alignment is not associated with any FSAR Update accident; it adds an additional backup source of CCW makeup and adds flexibility to the ability of operations to mitigate FSAR Update-analyzed accidents concurrent with certain failures. Accident and equipment malfunction probabilities and consequences are not increased.
	C-18	27. Makeup Water Sources to the CCW System OP F-2:VII, Rev. 1 (Unit 2) (LBIE Log No. 97-132) The procedure was revised to include the specific steps to align the firewater storage tank as a backup source to the CCW system, as described in the FSAR Update. The revision also requires the concurrence of Chemistry and Environmental Operations prior to using the primary water storage tank as a backup source for CCW makeup.
	C-22	34. Feed and Bleed of the CCW System PEP M-246, Rev. 0 (Units 1 & 2) (LBIE Log No. 97-182) This procedure de-concentrates the component cooling water (CCW) system's exhausted chemicals by continuously adding makeup water to the surge line while draining CCW from the heat exchanger through temporary connections.
	C-24	39. Notification of the Chemistry or Radiation Protection Sections OP O-3, Rev. 19 (Units 1 & 2) (LBIE Log No. 97-130) This procedure is part of the Chemistry Control Program. This revision adds a requirement that concurrence be obtained from Chemistry prior to using primary water in a nonradioactive system and specifically mentions use of primary water as makeup to the component cooling water (CCW) system. Section 9.2.2.3.3 of the FSAR Update states, "If the primary water makeup to CCWS valve is to be opened, the plant operator must obtain concurrence from the Chemistry and Radiation Protection Group."

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
	D-2	3. Inservice Testing (IST) Program Plan (Plan) 2nd 10-Year Interval, Revision 12 (Units 1 & 2) (LBIE Log No. 97-050) This revision included the following changes: • Removed manual stroke test of RHR-8701 and -8702 from the Inservice Test (IST) Plan P • Removed several component cooling water (CCW) Header “C” relief valves from IST Plan P • Removed partial stroke test requirement for emergency core cooling system (ECCS) check valves from IST Plan P
	D-6	12. Component Cooling Water (CCW) to Spent Fuel Pool Heat Exchanger Flow Test TP TB-9703, Rev. 0 (Unit 1) (LBIE Log No. 97-061) The purpose of this test is to provide data to evaluate the desirability of proposed future modifications that would increase the heat transfer capacity of the existing spent fuel pool heat exchanger. The test involves increasing the CCW flow from a design flow rate of 3000 gpm to approximately 5000 gpm for no more than five minutes.
	D-3	5. Equipment Control Guideline: CCW Surge Tank Pressurization System ECG 14.1, Rev. 2 (Units 1 & 2) (LBIE Log No. 97-074) ECG 14.1 was developed and implemented in 1996 to place administrative controls on the newly installed component cooling water (CCW) surge tank pressurization system. In 1997, PG&E elected to convert the ECG to a technical specification and submitted License Amendment Request (LAR) 97-05 to accomplish this (Reference DCL-97-074, dated May 22, 1997). In developing the LAR, a more conservative allowed outage time (AOT) was defined, and an additional surveillance requirement was identified. Revision 2 to ECG 14.1 was issued to have the ECG requirements coincide with the proposed LAR.
	F-14	29. Component Cooling Water (CCW) System Surge Tank FSAR Update Section 3.3.2.3.2.2 (LBIE Log No. 97-068) This change clarifies the FSAR Update description of the redundant CCW surge tank high level alarms to match actual plant configuration. Contrary to the previous description, there is only one high level alarm on the CCW surge tank.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
	F-15	30. Installation of the Component Cooling Water (CCW) Surge Tank Pressurization System FSAR Update Section 3.3.2.3.2.2 and Table 3.3-3 (LBIE Log No. 97-154) This change was made to reflect reflect the installation of the component cooling water (CCW) surge tank pressurization system. This change also corrected a statement in the tornado failure analysis table, which incorrectly stated that a maximum of 5000 gal. would spill from the surge tank in the event of tornado damage. The actual volume is 8100 gal. Additionally, this change clarified where the discharged 8100 gal would be directed.
	F-27	56. Relief Valve Criteria FSAR Update Section 9.2.2.2.9 (LBIE Log No. 97-052) The change addressed was the removal from FSAR Update Section 9.2.2.2.9, component cooling water (CCW) system valves, of the paragraph which contains the following information: "The relief valve [RV-52] on the component cooling water piping downstream of the excess letdown heat exchanger is sized for a tube break in the heat exchanger …. The relief capacity of this valve is such that the design pressure of this portion of the CCWS will not be exceeded." Existing DCPP calculation for this valve demonstrating capacity is an equilibrium calculation. Equilibrium assumptions like perfect mixing are not as conservative as a three-dimensional transient analysis would be. It would be difficult to perform an accurate two-phase, three-dimensional analysis, and it is believed that the results may indicate higher than design pressures.
	F-37	77. CCW Train Separation Valve Designation FSAR Update Table 3.9-9 (LBIE Log No. 97-063) The component cooling water (CCW) system is normally operated with its two safety-related trains cross-connected. Since a passive failure of one of the trains is postulated after 24 hours after a loss-of-coolant accident (LOCA) has occurred, the system is designed to allow separation of the trains using manually operated valves. The valves used to accomplish this train separation are considered to be active valves and are listed in the FSAR Update Table 3.9-9 list of active valves. The configuration of the system is such that the trains could be separated in several ways, using different combinations of manual valves. Table 3.9-9 was revised to list the valves actually used by procedure to perform the train separation.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
	G-9	19. CCW-1-TCV-130 Replacement (HOT TAP)--DCP M-049319 TES 2-001-N (Units 1 & 2) (LBIE Log No. 97-087) This design changed replaced the existing TCV-130 with one having better control characteristic for the given system parameters. Changes in the cooling water flow to the let down heat exchanger caused letdown temperature fluctuations resulting in boron concentration/reactivity. The existing TCV-130 was too large to maintain fine control, operating in the lower 2 percent of its control range. To allow the replacement of the valve without draining header "C" it was necessary to use a HOT TAP to install a by-pass line and smaller TCV-130. A HOT TAP allows the installation of branch connections to existing pipe while the system is "LIVE" which was required because component cooling water (CCW) for the spent fuel pool can not be isolated, even during outages.
	G-16	31. Revision of Technical Specification Bases 3/4.7.3 and 3/4.7.12 - Change Component Cooling Water System Design Basis Temperature Technical Specification Bases 3/4.7.3 and 3/4.7.12 (Units 1 & 2) (LBIE Log No. 97-221) The change to Technical Specification (TS) Bases 3/4.7.3, "Vital Component Cooling Water," and 3/4.7.12, "Ultimate Heat Sink," increased the maximum temperature at which the component cooling water (CCW) system may operate after a design basis event from 132□F for 120 minutes to 140□F for six hours after the event, returning to a maximum of 120□F thereafter. This revision reflects upgraded qualifications of CCW components and equipment cooled by CCW to show that they can function with the higher temperature cooling water. An administrative change to relocate the temperature limit from Bases 3/4.7.12 to Bases 3/4.7.3 was also made to improve consistency.
DCL 99 042	1	the NRC asked several additional questions regarding the CCW surge tank pressurization system to aid in completing its review of the LAR. On January 28, 1999, PG&E discussed these questions with the NRC staff. Based on the results of the discussion, the requested information is provided in Attachment B of this letter.

DCL #	Page	Descriptions
	Attachment B, page 1	NRC Question 1: What scenarios (component failure, tornado missile) can lead to rapid depressurization and off gassing, and what is the effect on CCW operation? PG&E Response: In Attachment B of PG&E letter DCL 98 096, dated July 9, 1998, "Supplement to License Amendment Request 97-05, Revision of Technical Specification 3/4.7.3.1," the results of a failure modes and effects analysis (FMEA) on the component cooling water (CCW) surge tank pressurization system and components is documented. The FMEA considered high and moderate energy line breaks, seismic interaction, and internally and externally generated tornado missiles. The FMEA demonstrates that the surge tank will not experience a failure that would result in the system being incapable of performing its intended function (maintaining system pressure during an event that results in high containment temperature). However, the analyses indicate that events can occur that will result in depressurization of the tank; however, these events are not required to be assumed to occur concurrent with an event that would cause high containment temperature. The effect of rapid depressurization of the CCW surge tank pressurization system was evaluated. Rapid depressurization will cause a small amount of nitrogen to come out of solution (approximately 3 percent by volume). As described in the response to Question 3, the surge tank provides enough static head to prevent nitrogen from coming out of solution in the CCW pumps (CCWPs) and lower sections of the system. In those locations where nitrogen would come out of solution, the heat transfer capabilities of the CCW system (CCWS) are not expected to be impacted. NRC Question 2: Are any changes warranted in minimum and maximum surge tank levels to account for a higher leak rate? PG&E Response: PG&E did not assume a higher CCWS leak rate after installation of the pressurization system. The originally licensed, nonmechanistic leak rate of 200 gallon per minute (gpm) for 20 minutes has continued to be assumed.

DCL #	Page	Descriptions
	2	Consequently, no change in the minimum surge tank level setpoints was required. If a higher leak rate assumption was required to be assumed, the two CCW surge tank level control valves can be recalibrated to maintain a higher level in the surge tank, narrowing the normal operating band. However, the high level alarm would not be changed since the corresponding level limit assures that the surge tank will not become water solid as a result of the worst case CCWS insurge. NRC Question 3: Are the CCWPs continuously vented such that nitrogen gas will not accumulate? PG&E Response: The CCWPs are not continuously vented because nitrogen gas will not accumulate in them. The CCWPs are not susceptible to nitrogen accumulation due to the elevation difference between the surge tank and the pumps. The maximum concentration of nitrogen in the CCWS is established by the gas pressure at the free surface of the CCW surge tank. The maximum concentration of nitrogen at the free surface, assuming 25 pounds per square inch gauge (psig) N2 pressure (maximum) with CCW temperature at 60ºF is 21.4 cc N2 / kg H2O. The water at the free surface is “saturated” with nitrogen. If the nitrogen pressure in the surge tank is lowered, nitrogen gas will come out of solution and conversely, if the pressure is raised, more nitrogen will go into solution. However, if CCWS pressure increases (as it does due to elevation changes between the surge tank and the pumps) there will be no increase in nitrogen concentration. The surge tank free surface is normally at approximately the 171’ elevation. The CCW surge tank surge lines are routed through the plant, connecting to the system return headers at the 80’ elevation. The CCWP suction piping is at the 74’ elevation. The elevation change provides 42 pounds per square inch (psi) pressure at the pump suction. The nitrogen gas pressure provides a nominal 20 psi pressure for a total of 62 psig at the pump suction. This does not include frictional losses between the surge tank and CCWP suction.

DCL #	Page	Descriptions
	3 5	As the static pressure in the CCWS increases (due to elevation change), the CCW fluid can accommodate more nitrogen in solution. However, the concentration does not increase since there is no source of nitrogen in excess of the tank's free surface concentration. At no point in the CCWS is the static pressure less than the surge tank free surface pressure which means that nitrogen will not come out of solution anywhere other than the surge tank. The CCWPs are installed at one of the lowest points in the system, where the static pressure is maximum and consequently at a point in the system with the least chance of nitrogen accumulation. NRC Question 4: Have overpressurization events been adequately addressed? PG&E Response: Mechanical Calculation M 353 analyzes the CCWS worst case over pressure scenarios. Each scenario was reviewed as a part of the design process for the nitrogen pressurization system. The review concluded that the original CCWS analysis result is still bounding. Specifically, the initial analysis assumes that the surge tank vent valve (RCV 16) is shut while the surge tank relief valve lifts at 10 percent accumulation. An additional pressure is added to account for the water column that exists between the normal liquid level and the relief valve inlet. This analysis establishes that the worst case pressure scenario results in a 33.9 psig pressure in the surge tank. This bounds the nitrogen pressurization system's maximum nominal pressure of 25 psig. NRC Question 6: What is the bounding high pressure scenario for the CCW system, what is the potential impact on the system, and how is this mitigated? PG&E Response: All the analyses for maximum CCWS pressure conditions assume that the surge tank vent valve (RCV 16) is closed and the surge tank relief valve (RV 45) is lifting at 10 percent accumulation. An additional static head is included to account for the water column above the normal liquid level to the inlet of the surge tank relief valve. The total pressure per Calculation M 353 is 33.9 psig. There are no credible system transients or inleakage events that exceed the capacity of RV 45 (Calculations M-914 and M-209). These analyses considered separately inleakages from the reactor coolant pump thermal barriers, residual heat removal (RHR) heat exchangers, letdown and excess letdown heat exchangers, seal water heat exchanger and post loss of coolant accident (LOCA) insurge. This analysis was reviewed as part of the design process that installed the nitrogen pressurization system. It was determined that the impact on the CCWS maximum pressure condition is bounded by the initial analysis.

DCL #	Page	Descriptions
	6	NRC Question 7: What is the bounding low pressure scenario for the CCW system, what is the potential impact on the system, and how is this mitigated? PG&E Response: The bounding low pressure scenario is a 200 gpm out leakage event. For conservatism, the normal and backup supply of nitrogen to the pressurization system is assumed to be unavailable. The analysis shows that after the postulated 200 gpm leak for 20 minutes, a slight vacuum of 13.2 pounds per square inch absolute (psia) exists at the surge tank free surface. The impact of this reduced pressure is reduced net positive suction head (NPSH) on the CCWPs. However, the reduced NPSH will still support a worst case CCWP operation at 14,000 gpm per pump at a fluid temperature of 250ºF. This is sufficient flow for both emergency and normal operations. The CCW surge tank is designed to withstand a total vacuum (0 psia). NRC Question 8: What are combined temperature and pressure effects on degas scenario (submittal only considers these separately)? PG&E Response: The worst case pressure scenario for the CCWS is a complete and rapid loss of the nitrogen pressurization system. This event would occur with a breach of the lines in the pressurization system (passive failure), or simultaneous failures of the back pressure and supply regulators (passive components during the injection phase). The impact of this scenario is worst in the highest components of the system where static pressure is lowest. The containment fan cooler units (CFCUs) whose highest elevation is 161', approximately 10' below the free surface of the surge tank are the most impacted.

DCL #	Page	Descriptions
		The worst case temperature scenario is the CFCU outlet temperature during the injection phase of a LOCA. Here the CCW exit temperatures from the CFCUs are the highest that the system experiences, approximately 239ºF. Consistent with the DCPP licensing basis, the worst case temperature and worst case pressure scenario do not occur simultaneously (no postulated passive failure during the first 24 hours of a DBA). However, to be conservative and ensure that the limiting case has been bound by analysis, the simultaneous worst case pressure and temperature degas scenarios have been considered concurrently in a refined analysis. The result of this analysis shows that the original approximation of 3 percent by volume that comes out of solution at the worst case temperature (described in PG&E Letter DCL 97 151 dated August 28, 1997, "Response to NRC Staff's Concerns Regarding Installation of the Component Cooling Water Surge Tank Pressurization System - Diablo Canyon Power Plant, Units 1 and 2)," was conservative and bounds the combined worst case temperature and pressure degas scenario.
	7	NRC Question 9: What is the effect of out leakage event with surge tank level starting at low level alarm setpoint? [Why did the analysis assume level initially at high alarm setpoint; this seems to be non conservative?] PG&E Response: The licensing basis impact evaluation (LBIE) sent with PG&E Letter DCL 97 108, dated June 12, 1997, "10 CFR 50.59 Safety Evaluation for Installation of the Component Cooling Water Surge Tank Pressurization System," referenced Calculation M 175, Revision 2, which addresses this question. Calculation M 175 was revised as part of the pressurization system design evaluation. M 175, Revision 2, states that "post leakage surge tank pressure will be minimized by using the smallest initial free volume and the maximum post leakage free volume." The analysis assumed that the initial gas volume in the surge tank is based on the highest liquid level, minimizing the gas volume. A smaller gas volume results in lower postleakage surge tank pressure.

DCL #	Page	Descriptions
		The liquid volume in the tank is assumed to correspond to the tank's lowest level. A lower postleakage liquid level results in a lower NPSH for the CCWPs and hence is most conservative for this analysis. To be even more conservative, the calculation assumed that the nitrogen supply system is unavailable during the out leakage, so that no nitrogen (or air) make up is available. The analysis shows that after the postulated 200 gpm leak for 20 minutes, a slight vacuum of 13.2 psia exists at the surge tank free surface. The impact of this reduced pressure is reduced NPSH on the CCWPs. However, the reduced NPSH will still support a worst case CCWP operation at 14,000 gpm per pump at a fluid temperature of 250ºF. This is sufficient flow for both emergency and normal operations.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
	8	NRC Question 10: What are the consequences of a passive failure after 24 hours? PG&E Response: A passive failure of the pressurization system has the worst case effect of depressurizing the CCW surge tank. The CCW surge tank was originally designed and installed to be open to atmosphere. All pressurization tubing and components tap into the surge tank above the liquid level meaning that a pressurization system breach results only in gas leakage, but no fluid leakage. Twenty-four hours after a LOCA coincident with a loss of offsite power (LOOP), the heat load on the CFCUs from containment is not sufficient to raise the fluid in the CFCU coils above saturation conditions with an unpressurized surge tank. The CFCUs represent the worst case position for loss of pressure in the CCWS due to their elevation (140' elevation of containment) and the heat input to CCW from the fans. As stated in Question 1, the affect of rapid depressurization (and release of about 3 percent by volume of N2) is not expected to impact CCWP operation, heat exchanger capability, or valve operability.
	8	NRC Question 11: Contrary to what is stated in the licensee's LBIE, single active failures of components must be considered (regulators, level control valves, etc.). Also, any vulnerabilities due to loss of instrument air or loss of electrical power must be assessed. Even though the function of the pressurization system may be passive, the licensee must confirm that an active failure will not compromise performance of the CCWS.

DCL #	Page	Descriptions
		PG&E Response: The intent of the statement in the LBIE was that no single active failures are considered for the equipment installed as part of the nitrogen pressurization system. The pressurization system components are considered passive and only relied upon to maintain system boundary integrity during a DBA. The pressurization system is comprised of tubing, relief valves, regulators, manual valves, instruments, and pressurized cylinders. The relief valves and regulators are disc and spring, or diaphragm and spring devices that respond to preset system pressure. The instruments do not have a safety function. The remaining original system components are still vulnerable to single active failures consistent with the DCPP license. No additional single failures have been identified in the original equipment that result from the pressurization system installation. The level control valves for the CCWS surge tank are normally closed and fail closed on loss of instrument air. They have no active function during an accident; consequently, no active failure is postulated for these valves. All motor operated and air operated valves with active safety functions have been analyzed for impact due to increased CCW surge tank pressure. See Question 17 for a detailed discussion. The pressurization system does not impact a CCWP's ability to perform its safety function. Calculation M 175 analyzes the new scenario for system outleakage and resultant surge tank vacuum. The CCWPs will not become vapor bound during normal operation and rapid degassification as described in Question 3. The normal source of nitrogen pressure (and alternate instrument air pressure) is design Class II and not postulated to be available during a DBA. Failure of these sources of pressure were previously considered. The Class I source of nitrogen was installed to prevent challenging plant operability (on loss of normal nitrogen source). To be conservative, none of the compressed gas sources are assumed available during a DBA. Single failures in the electrical systems supplying the CCWS have been considered. Installation of the nitrogen pressurization system does not impact that analysis. The pressurization system uses electricity for instrumentation only; none of which is credited for postaccident operation.

DCL #	Page	Descriptions
		NRC Question 12: Why isn't the backpressure regulator sized to accommodate the insurge due to LOCA heat input; isn't this more limiting than normal level fluctuations? Is the backpressure regulator designed for both liquid and gas service?
	9	PG&E Response: The backpressure regulator is not expected to relieve any pressure during the first few minutes of a DBA. During the first few minutes, the CCWPs are deenergized and no heat is being transferred to the CCWS and hence, no insurge. Note, that heat is being transferred into the fluid in the CFCUs, but it is expected that the amount of thermal expansion due to that heat transfer is not sufficient to actuate the backpressure regulator. The maximum post LOCA insurge rate was calculated in Calculation M 209. This analysis shows a maximum instantaneous insurge of 0.832 standard cubic feet per minute (SCFM). The backpressure regulator has a capacity of 0.748 SCFM. The CCW surge tank relief valve is capable of 2424 SCFM in case the surge tank pressure exceeds 30 psig. There is a narrow margin between the surge tank relief valve setpoint (30 □ 2 psig) and the minimum pressure required to maintain the fluid in the CFCUs subcooled during the accident (17 psig). Currently the span between the back pressure regulator's shut off and the supply regulator's highest outlet pressure is less than 1 psig. This accounts for setting tolerance and control point deviations. A backpressure regulator with a higher capacity would have a wider operating band and would cause the shut off point and maximum supply pressure to overlap. See Attachment C for a pictorial representation. The backpressure regulator is designed for gas service only. Calculation M 209 shows that with a post LOCA insurge, the surge tank under worst case conditions will not go solid, and that the backpressure regulator will not be required to pass water.

DCL #	Page	Descriptions
		NRC Question 13: Confirm adequacy of RV 45 capacity. RCP thermal barrier leakage; maximum insurge; failed open regulator; failed open control valve; combination of these? PG&E Response: The maximum reactor coolant system (RCS) inleakage to the CCWS has been determined in Calculation M 914. This analysis shows that a maximum insurge rate of 258.6 gpm will result from a double-ended tube break in an RHR heat exchanger. The maximum calculated instantaneous surge tank insurge occurs post LOCA and is bounded by 373.4 gpm. This insurge happens early in the accident (before 24 hours) when the CCWS heat load is highest. Combining the worst case RCS inleakage (or any other RCS inleakage) with the maximum insurge would not be consistent with the DCPP licensing basis. Other credible single failures during nonaccident operation include a failed open nitrogen supply regulator (25 SCFM) and a failed closed back pressure regulator. Note that the CCWS make up valves are air to open, fail closed. Since the make up valves are level controlled, it is not credible that they will open as a result of RCS inleakage and associated surge tank level increase.
	11	The capacity of RV 45 is 483 gpm at 70ºF and 2424 SCFM at 10 percent accumulation. Consistent with the DCPP licensing basis, this relief valve is not postulated to have an active failure. Combining the worst case RCS inleakage (258.6 gpm) with the worst case system failures (back pressure regulator failed closed, supply regulator failed open at 25 SCFM or 187 gpm) results in a total of 445 gpm. This is below RV 45's capacity. NRC Question 14: What are criteria for maximum and minimum surge tank level and pressure; basis? PG&E Response: The CCW surge tank high pressure limit is 30 psig and is based on ensuring that all the piping and components comprising the CCW system are maintained below their maximum design pressures. The surge tank itself is designed to withstand 150 psig at 300ºF and a vacuum of 0 psia. The CCW surge tank low pressure limit is 17 psig and is based on maintaining the CCW inventory in the CFCU coils subcooled after a concurrent LOCA and LOOP.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
	11	The CCW surge tank high level limit is 27 inches above normal liquid level and is based on engineering judgment to allow for reasonable surges and swells before alerting the operator to possible in leakage. Above 27 inches there is a chance that the surge tank will go solid (no available gas space) during a post DBA surge tank insurge. CCW surge tank low level limit is 4000 gallons and based on providing adequate NPSH for the CCWPs after withstanding a 200 gpm leak for 20 minutes.
	12	NRC Question 15: If the CCW system was originally designed to accommodate 30 psig surge tank pressure (RV 45 setpoint), why was replacement of Unit 1 CCW pump lube oil coolers required? PG&E Response: In September 1994, the possibility of overpressurizing the CCWP lube oil cooler shell sides was identified. This occurred before identification of the CFCU water hammer issue that resulted in installation of the pressurization system. The evaluation noted that with high pressure radioactive inleakage to the CCWS, RCV 16 (surge tank vent isolation valve) would close and the system pressure would increase until RV 45 lifted. The static head at the lube oil cooler plus the postulated additional pressure of RV 45 (surge tank relief valve) exceeded the design pressure of the lube oil coolers before the CCWS was to be pressurized with nitrogen. The lube oil cooler end bonnet replacement occurred simultaneously but independently of the pressurization system installation.

DCL #	Page	Descriptions
	12	NRC Question 16: What are the pressure effects on the current leakage criteria of 200 gpm for 20 minutes (licensee must demonstrate that the pressure effects are insignificant such that the criteria should remain unchanged, or establish new criteria)? PG&E Response: The CCW design basis leakage rate is defined as a nonmechanistic leak of 200 gpm. The CCWS surge tank volume provides operators with 20 minutes to locate and stop the leak, or align the CCWS into separate trains. No basis or detailed evaluation for the maximum leak rate of 200 gpm exists. Since the 200 gpm value had not been calculated, it was not previously considered to be dependent upon parameters such as crack size, system pressure or leak location. Design Change Package (DCP) M 49284 and DCP M 50284 treated this nonmechanistic leak rate in this manner. The NRC has requested that PG&E evaluate the impact of the increased CCWS pressure on the CCW leak rate and time allowed for operator response. The following method was used to determine this new leak rate / response time: 1. Determine a reasonable leak location and corresponding CCW system pressure with an unpressurized surge tank. The system pressure minus atmospheric pressure at this location is the delta P to be considered across the postulated break. 2. Add 25 psi due to installation of the pressurization system to the above delta P, and estimate the new leak rate, assuming that the break behaves as a square edged orifice, and leak rate is proportional to the square root of delta P. 3. The new operator response time would be 20 minutes X (200 gpm/new leak rate). As discussed with the NRC, postulation of a leak location at the discharge of the CCW pumps is a reasonable assumption. Considering the normal CCW system operating configuration, consisting of two CCW pumps operating with one CCW heat exchanger in service in Mode 1 (Power Operation), the new leak rate is estimated to be 222 gpm at the CCW pump discharge, based on the above approach. (Calculation M 1017 Balance 19 is a good model for CCW normal operation). Considering this new leak rate, an operator response time of approximately 18 minutes would be determined, based on this approach, if the leak rate were to be considered as mechanistically derived. This is a small change in operator action time and is not considered significant. Due to the minimal pressure effects, the criteria of a 200 gpm nonmechanistic leak will remain unchanged.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
	13	NRC Question 17: Explain the d/p evaluation of valves. PG&E Response: This question was withdrawn per telecon with Steve Bloom and Jim Tatum, January 28, 1999. The answer is included, however, because it supports other NRC questions. Air and motor operated valves (AOV and MOV) are designed and installed to open or close with certain maximum differential pressures across the discs. PG&E evaluated the impact of elevating the CCW system pressure by a nominal 20 psig (17 25 psig) on the operation of AOVs and MOVs in the system. This evaluation was documented in the subject DCPs (DCP and M 049284 M 050284) and the LBIE for those DCPs which referenced Calculations M 320 (U1) and M 573 (U2). Each of these documents were submitted to the NRC with PG&E Letter DCL 98 096 on July 9, 1998. The evaluation in the LBIEs, DCPs, and calculations states that the AOVs and MOVs in the CCWS are not affected by increasing the surge tank pressure since upstream and downstream pressures rise equally (d/p remains constant). A few exceptions were noted in the above evaluations. These valves connect the CCWS to other systems (makeup water valves LCV 69, LCV 70) and CCWS containment isolation valves (FCV 357, FCV 750, FCV 749, FCV 363, FCV 356 and FCV 361) The makeup valves' maximum differential pressure was evaluated previously and considered the maximum makeup water system pressure minus the lowest CCWS pressure. Adding more pressure to the CCWS actually lowered the d/p that the LCV 69 and LVC 70 must operate against.

DCL #	Page	Descriptions
	14	The containment isolation valves (CIV) maximum upstream pressure was based on the lift setpoint for associated relief valves. For example, the section of CCW pipe that serves the RCP lube oil coolers is isolated by containment isolation valves FCV 356, FCV 363 and FCV 749. To prevent overpressurization of these lines due to thermal expansion when isolated, RV 51 is installed and lifts at 150 psig. To be conservative, the pressure on the component side of the CIVs is taken to be the lift pressure of RV 51 or 150 psig. This is above the normal system pressure of nitrogen pressurizing CCWS. The system side of the CIVs is exposed to CCWS pressure which is now higher than before, and hence, the valves' maximum d/p is lower as a result of the pressurization system modification. Stem ejection forces were also analyzed for the nonbutterfly type valves in the system and found to be bounded by previous analysis. NRC Question 18: Calculation M 998 uses a surge tank liquid level of 171' 2". Does this bound the minimum surge tank level for Unit 2, also? PG&E Response: Both units' surge tanks lowest low level controllers have a design minimum level of 171' 2".
DCL 99-080	2	3. Component Cooling Water Heat Exchanger Cleaning During Each Refueling Cycle Source Document(s): PG&E Letter DCL-94-037, "Auxiliary Saltwater System Operability," dated February 15, 1994 Original Commitment In accordance with Maintenance Procedure MP M-56.16, "Heat Exchanger Tube Cleaning," the heat exchanger tubes are mechanically scraped during each refueling outage (nominally every 18 months). Revised Commitment In accordance with Maintenance Procedure MP M-56.16, "Heat Exchanger Tube Cleaning," the heat exchanger tubes are mechanically scraped during each refueling outage (nominally every 24 months).

DCL #	Page	Descriptions
	3	Justification for Change The time between component cooling water (CCW) heat exchanger (HX) tube scraping has been extended to 24 months in anticipation that refueling cycles could be extended to that duration. By extending the interval to 24 months there is a potential that the HX will undergo additional fouling. Fouling can be due to biofouling, debris accumulation, siltation, or deposition. Each of these mechanisms is addressed as follows: A. Biofouling has not been noted since implementation of continuous chlorination. Through continuous injection of sodium hypochlorite solution, the auxiliary saltwater (ASW) pipe and the CCW HXs are maintained free of slime or other life that could cause an insulating film to form on the HX tubes. PG&E's 6-month biofouling inspections have shown no signs of biofilm since continuous chlorination was implemented. Lengthening the cycle will not make the HX more vulnerable to biofouling. B. Debris accumulation on the inlet tubesheet is indicated in the control room as a rising differential pressure (d/p) across the CCW HX. A limit for cleaning the HX is provided in Surveillance Test Procedure (STP) I-1A, "Routine Shift Checks Required by Licenses." A longer cycle will not impact PG&E's ability to diagnose or respond to an elevated d/p. C. Since the CCW HXs operate at design flow whenever they are in service, PG&E has never noted any accumulation of silt or sediment. This is because the HX flow rate is great enough to prevent silt from accumulating in the waterboxes or in the tubes. A longer cycle will not precipitate an increase in accumulation of sediment.

DCL #	Page	Descriptions
		D. The major deposition mechanism in the CCW HXs is calcium carbonate deposited on the tube outlets on the Unit 2 CCW HXs. Due to a slightly different configuration, Unit 1 is not subject to this phenomenon. When the Unit 2 CCW HXs are taken out of service, the saltwater side remains partially full. Due to the position of the cathodic protection system reference and protection anodes, this causes the cathodic protection current to be maximized, which causes the deposition of carbonate. This deposition has been greatly reduced by a change to the Operating Procedure E-5:IV, "Auxiliary Saltwater System - Changing Over Pump and Heat Exchanger Trains," which now requires operators to vent the Unit 2 CCW HXs allowing water to drain from the saltwater side. As additional assurance, should deposition occur, it could be detected by an increase in the d/p which is monitored in the control room.
	4	E. There has been slight deposition of a brown material throughout the ASW system. This consists of minerals precipitated from seawater by the chlorine injection. F. HX testing after 20 months of operation yielded results similar to those obtained after 18 months, to within experimental uncertainty. This demonstrates that the cycle length increase does not impact CCW HX performance.
DCL-99-127	Attachment B Attachment B	PROPOSED FINAL SAFETY ANALYSIS REPORT CHANGES (Pages 9.2-7, 9.2-25, 9.2-26 and 9.2-29) Insert A (page 9.2-25) The ASW system is designed so that it may be aligned into two separate vital loops by manual manipulation of various system valves following a passive failure. This provides totally redundant and separate trains, which ensures that a passive failure during the long term period following an accident will not cause a total loss of ASW. Due to the potential for a loss of CCW system function in the event of a bus failure, the ASW system should not be split into separate trains unless required to mitigate a passive failure. Insert B (page 9.2-26) In the injection phase of the accident no operator action is required for operation or reconfiguration of the ASW system and its components. During the long term period following the accident, the ASW system may be aligned, after evaluation by the Technical Support Center, into two separate redundant trains, each consisting of a pump, supply header and a CCW heat exchanger, to mitigate a passive failure. This configuration provides full protection against a passive failure and provides the minimum required long term cooling requirements. Refer to Section 9.2.7.2.7 for heat removal capability in this configuration.

NRC Outgoing Correspondence-CCW System

DCL #	Page	Descriptions
	Attachment B	Insert C (page 9.2-29) If the ASW system is aligned in the split train configuration during long term post-accident operation because a passive failure has occurred, each separate train of ASW is capable of supplying the minimum heat removal capacity required.
DCL-99-132	Enclosure Enclosure	In PG&E Letter DCL-99-127, “Additional Information Regarding August/September 1997 Design Inspection,” dated September 29, 1999, PG&E submitted information discussed during a June 10, 1999, conference call with the NRC staff regarding the August/September 1997 design inspection at the Diablo Canyon Power Plant. That submittal included proposed changes to Final Safety Analysis Report (FSAR) Sections 9.2.2, “Component Cooling Water System,” and 9.2.7, “Auxiliary Saltwater System.” In response to additional discussions with the NRC staff, PG&E has further revised those sections to reflect long term postaccident component cooling water system and auxiliary saltwater system operation. INSERT A: Due to its vulnerability to a loss of inventory, the CCW system should be split into separate trains as soon as possible after aligning for long-term post LOCA recirculation if plant conditions are acceptable. The decision to split CCW trains will be made by the Technical Support Center based on the physical integrity of the trains, the availability of active components, and the reliability of power systems. INSERT B: During post-LOCA long term recirculation, the ASW system should remain cross-tied to assure that any active failure in the ASW or CCW system would not result in the loss of CCW system cooling. While vulnerable to a passive failure in this configuration, the ASW system capacity is such that the ASW system function would not be affected. A decision to split the ASW system into separate trains to mitigate a passive failure would be made by the Technical Support Center if it became required.

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

NRC Outgoing Correspondence-CCW System

Enhanced in DCM	Enhanced in FSAR	Comments

Published	*NRC Incoming Date: 03/11/1992*
TITLE	*#NTP Subject: Closeout of Generic Letter (GL) 89-13, "SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT," DATED JULY 18, 1989 (TAC NOS. M73992 AND M73993)*
IEIR #	*50-275/90-28 and 50-323/90-28*
ACTS #	

#DATE 11/03/1992
ACTS 2232
#NTP
Subject: Closeout of Generic Letter (GL) 89-13, "SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT," DATED JULY 18, 1989 (TAC NOS. M73992 AND M73993)
Docket Nos. 50-275
and 50-323
Mr. Gregory M. Rueger
Senior Vice President and General Manager
Nuclear Power Generation Business Unit
Pacific Gas and Electric Company
77 Beale Street, Room 1451
San Francisco, California 94106
Dear Mr. Rueger:
SUBJECT: CLOSEOUT OF GENERIC LETTER (GL) 89-13, "SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENTS, DATED JULY 18, 1989 (TAC NOS. M73992 AND M73993)

By letters dated January 26, 1990, and November 25, 1991, you responded to GL 89-13 for Diablo Canyon Units 1 and 2. In the January 26, 1990 letter, you committed to establish programs to implement each of the five recommended actions of GL 89-13, or to implement an equally effective alternative course of action. In the November 25, 1991 letter, you stated that implementation of the initial program actions for each of the five recommendations of GL 89-13 had been completed for both units at Diablo Canyon. The NRC staff has reviewed your response to GL 89-13 and finds that it fulfills the reporting requirements of the generic letter. This completes our review of this issue and closes TAC Nos. M73992 and M73993.

We remind you that if a licensee chooses a course of action different from the recommended actions of the generic letter, the licensee should document and retain in appropriate plant records a justification that the heat removal requirements of the service water system are satisfied by use of the alternative program. If you have any questions regarding this matter, please contact me.

Sincerely,
Harry Rood, Senior Project Manager
Project Directorate V
Division of Reactor Projects III/IV/V
Office of Nuclear Reactor Regulation
cc:
Regional Administrator, Region V
U.S. Nuclear Regulatory Commission
1450 Maria Lane, Suite 210
Walnut Creek, California 94596
Mr. Peter H. Kaufman
Deputy Attorney General
State of California
110 West A Street, Suite 700
San Diego, California 92101
Mr. John Hickman
Senior Health Physicist
Environmental Radioactive Mgmt. Unit
Environmental Management Branch
State Department of Health Services

714 P Street, Room 616
Sacramento, California 95814
Managing Editor
The County Telegram Tribune
Johnson Avenue
P. 0. Box 112
San Luis Obispo, California 93406
Ms. Sandra A. Silver
Mothers for Peace
660 Granite Creek Road
Santa Cruz, California 95065
Ms. Nancy Culver
192 Luneta Street
San Luis Obispo, California 93401
NRC Resident Inspector
Diablo Canyon Nuclear Power Plant
c/o U.S. Nuclear Regulatory Commission
P. 0. Box 369
Avila Beach, California 93424
Richard F. Locke, Esq.
Pacific Gas & Electric Company Post Office Box 7442
San Francisco, California 94120
Michael M. Strumwasser, Esq.
Special Assistant Attorney General
State of California
Department of Justice
3580 Wilshire Boulevard, Room 800
Los Angeles, California 90010
Chairman
San Luis Obispo County Board of
Supervisors
Room 370
County Government Center
San Luis Obispo, California 93408
Dr. R. B. Ferguson, Energy Chair
Sierra Club California
6715 Rocky Canyon
Creston, California 93432
Ms. Jacquelyn C. Wheeler
3303 Barranca Court
San Luis Obispo, California 93401

[New Query] [Table of Contents] [Previous Submittal] [Next Incoming]

Published	*NRC Incoming Date: 08/24/1990*
TITLE	*#NTP Subject: WORKSHOPS ON BACKFITTING AND EVENT REPORTING*
IEIR #	
ACTS #	*640*

#DATE 24/08/1990
ACTS 640
#NTP
Subject: WORKSHOPS ON BACKFITTING AND EVENT REPORTING

TO: ALL LICENSEES OF OPERATING NUCLEAR POWER PLANTS AND HOLDERS OF CONSTRUCTION PERMITS FOR NUCLEAR POWER PLANTS

SUBJECT: WORKSHOPS ON BACKFITTING AND EVENT REPORTING

The NRC is organizing a series of workshops on two separate topics: event reporting and backfitting. NUMARC has cooperated with the NRC in developi these workshops. There will be four regional workshops (in the Philadelphia, PA; Atlanta, GA; Chicago, IL; and Dallas, TX areas). The ti frame is late-September through early November 1990; Table 1 provides more detailed information regarding dates and locations for the workshops. The purpose of these workshops is to exchange views on NRC policy and industry experiences in the subject areas. Among other things, we will be interest in constructive suggestions toward improving NRC policy and resolving implementation problems in both the backfitting and event reporting areas. The two topics are distinct, and will be handled separately in the planned workshops; but it is more efficient to cover both topics in a single serie of regional workshops, than in completely separate workshops for each topic. As indicated in Table 1, we plan to devote one day of meeting time to discussion of each topic in the four workshops. There will be active participation in all the workshops by senior NRC management and staff from the cognizant headquarters offices (AE0D, NRR, OGC and RES) and the NRC regional offices.

With regard to the first workshop topic (i.e., backfitting), all applicant and licensees have been sent a copy of NUREG-1409, "backfitting Guidelines". That report provides a summary of NRC's current backfit poli and procedures, and includes a number of questions-and-answers covering various aspects of the day-to-day implementation of backfitting. Also, th recent report on the results of NRC's regulatory impact survey (Draft NUREG-1395) contains licensee commentary on current backfit issues to be discussed in the workshops (e.g., informal guidance as "requirements"; proliferation of requirements: cumulative effects of requirements). We encourage meeting participants to become familiar with both reports in preparation for these workshops. This will ensure more useful interaction and clarification of specific points in the workshops. With this in mind, we have prepared Table 2 (and Supplement) as a preliminary agenda for the backfitting discussions in the workshops. We encourage vigorous participation by the nuclear utility industry to develop a better mutual under-standing of backfitting issues, and to identify possible areas for improvement.

With regard to the second workshop topic, (i.e., event reporting), we have prepared Table 3 (and Supplement) as the proposed agenda for discussion of issues in this area at the workshops. Event reporting is another problem area identified in Draft NUREG-1395; and the proposed agenda is intended t address both NRC and licensee concerns regarding current reporting requirements and practices, with the principal focus on 10 CFR 50.72 and 1 CFR 50.73. Our aim is to clarify NRC's needs and intent in the reporting area, and to revise existing reporting requirements and guidance, if necessary, to deal with identified problems. As with the backfitting topi we encourage substantive interactions in the workshops on this issue to ma this a beneficial exercise to all participants.

The workshops will be public meetings, arranged by the NRC; and they will announced routinely in the Federal Register. After the four workshops hav been held, we plan to write a report on our conclusions and recommendation for follow-up action. One of the things to be determined is whether it is neces-sary to recommend rulemaking in the subject areas. Your views on th

and other topics can be expressed at the workshop; you may provide to us i advance of the meetings any questions, views, or comments on the subject matters that you wish to have considered in the workshops. Alternatively, you may provide to us outside the workshop context your views on these topics, and we will consider them as we develop policy recommendations. Address any written comments as indicated below.

I look forward to these workshops as a milestone in improving our regulati and your response to our policies in these areas.

Edward L.Jordan, Director
Office for Analysis and Evaluat
of Operational Data

Enclosures:

Table 1 - Workshop Dates and Locations
Table 2 - Backfit Workshop Agenda
Table 2 Supplement - Backfit Discussion Items
Table 3 - Event Reporting Agenda
Table 3 Supplement - Event Reporting Discussion Items

NRC Contact: Denwood F. Ross, Deputy Director
Office for Analysis and Evaluation
of Operational Data
Telephone - (301) 492-7361

Send Comments To: U.S. Nuclear Regulatory Commission
ATTN: Denwood F. Ross
Mail Stop MNBB-3701
Washington, DC 20555

TABLE 1

Regional Workshops on Backfitting and Event Reporting

DATES AND LOCATIONS: The schedules and locations for the meetings a as

follows:

Region I: Stouffer Valley Forge Hotel
480 North Gulph Road; King of Prussia, PA 19406
(215) 337-1800

Backfitting Workshop: October 1, 1990; 9:00 a.m. - 5:00 p

Event Reporting Workshop: October 2, 1990; 9:00 a.m. - 5:00 p

Region II: Omni Hotel
100 CNN Center; Atlanta, GA 30335
(404) 659-0000

Backfitting Workshop: September 27, 1990; 9:00 a.m.- 5:00 p.m.

Event Reporting Workshop: September 28, 1990; 9:00 a.m. - 5:0 p.m.

Region III: Ramada Hotel O'Hare
6600 North Mannheim Road; Rosemont, IL 60018
(708) 827-5131

8backfitting Workshop: October 15, 1990; 9:00 a.m. - 5:00 p

Event Reporting Workshop: October 16, 1990; 9:00 a.m. - 5:00 p

Regions IV/V: Sheraton CentrePark Hotel
1500 Stadium Drive East; Arlington, TX 76011
(817) 261-8200

8backfitting Workshop: November 7, 1990; 1:30 p.m. - 5:30 p.m. November 8, 1990; 9:00 a.m. - 12:30 p.m.

Event Reporting Workshop: November 8, 1990; 1:30 p.m. - 5:30 p.m. November 9, 1990; 9:00 a.m. - 12:30 p.m.

TABLE 2

Agenda for Backfitting Workshops

Topic	Presentation/Discussion
Summary of NUREG-1409, "Backfitting Guidelines"	Brief presentation by NRC and general discussion
Legal Aspects of Backfitting	
- NRC Perspectives	Brief presentation by NRC
- Industry Perspectives	Brief presentations by NUBARG and NUMARC
- Questions/Comments on Presentations	General discussion
Bulletins and Generic Letters	Brief presentation by NRC and General discussion
Utility Perspectives on Backfit Issues and Description of Utility Backfit Evaluation	Presentations to be coordinat by NUMARC and general discuss
IPE/IPEEE - Severe Accident Closure Status	Brief presentation by NRC and general discussion
NRC Guidance on Regulatory and 8backfit Analyses	8rief presentation by NRC and general discussion
Rulemaking vs More Informal Issuance of Requirements	General Discussion
Backfit Appeal Process Plant Specific/Generic	General Discussion

Supplement to Table 2

(Suggested Topics For Airing In Backfit Workshop Discussions)

1. Discuss in some detail the NRC backfit review process and the CRGR role, and the industry's understanding of that role/process, includin views on how well it works and constructive suggestions for improveme along the lines suggested by the more specific questions below.

2. How does NRC categorize proposed backfits (i.e., cost-justified safet enhancement, compliance exception, adequate protection exception)? I particular, why do many bulletins and generic letters come under the compliance exception of 50.109? Also touch on rare use of adequate protection exception (e.g., PTS rule & implementing regulatory guide)

3. How does a utility determine on its own whether or not a plant/procedure modification is needed for safety? Does a utility go through a process similar to NRC's backfit review process? In that context, as examples, discuss the utilities' experience and views regarding the following:

   - Generic Letter 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment"

   - Reg. Guide 1.99, "Radiation Embrittlement of Reactor Vessel Materials"

   - Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment"

- Generic Letter 88-20, "Individual Plant Examination of Severe Accident Vulnerabilities"

- Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance,

- Generic Letter 88-17 (and forerunner GL 87-12), "Loss of Decay Hea Removal"

- (Other pertinent examples of regulatory actions in the last 2 year of interest/concern to the industry, e.g., counterfeit and fraudulently marketed products, in-service testing of valves, loss of shutdown margin, loss of fill oil in pressure transmitters, etc

4. Do you agree/disagree that there was a safety need for the regulatory actions taken in the above examples? In these and other instances, h would the industry propose that NRC act differently? Was safety improved (i.e., significantly, some, not at all) by these actions? Which, if any could/should have been postponed or withheld?

5. How would industry propose that NRC react when there seems to be ampl evidence (as in the above examples, or currently in evaluating operating experience with solenoid-operated valves) that something needs to be done for improvement of safety?

6. What has been the cumulative impact of NRC-approved backfits over the last two years? More specifically:

   a. What is your tally of the costs of implementing those backfits (bo total and individually) vs the costs estimated by NRC? Is there a flagrant example(s) where the backfit involved would not have pass the cost-benefit test (where applicable), if more accurate cost estimates had been used by NRC?

   b. Is there any objective evidence that the bulletins/generic letters involved produced safety improvements or reduced risk? Does the industry, or any individual utility, have a method for cumulative accounting of risk or safety benefit as a result of NRC-approved backfitting (or even attempt such accounting, for that matter)?

   c. Does any utility believe that NRC-approved backfitting has adverse impacted the safety of operations at their facility, or significant-ly and unnecesarily interfered with other important aspects of the conduct of operations in your plant? For example:

      - What has been utility experience with the scheduling of wor during outage? Have NRC-specified schedules for implementation of approved backfits been reasonable? If no were you able to obtain relief from specified schedules, and/or what are your suggestions for improving the process that regard?

      - Have any NRC-approved backfits delayed or otherwise adverse affected major intended improvements at your plant undertak on your initiative? Were any such initiatives considered b you to be of higher overall priority than the NRC-approved backfit? Were any clearly of greater safety importance in your view? (See item 3. above in this context.)

7. Have you had any diffculty in understanding the regulatory basis or decision rationale for the bulletins and generic letters transmitted you by NRC? Cite examples of specific difficulties. In this context discuss the following:

   a. NRC's use of the 50.54(f) generic "information request" (vis-a-vi backfitting, in accordance with 50.109), and the cost to industry such requests, e.g., the IPE Generic Letter.

   b. CRGR initiatives to improve bulletin/generic letter format and boilerplate.

   c. Recent NRC/RES initiatives to improve NRC regulatory analysis guidance and clarify the relationship between the terms "regula-t analysis" and "backfit analysis" (as specified in 50.109 and in t CRGR Charter).

8. What are the industry's views regarding the use of rulemaking vis-a-v bulletins/generic letters as a vehicle for NRC backfitting actions? Refer to the backfitting examples above and indicate which, if any, y

think should have been handled by rulemaking. What are the relative benefits, if any, of more rulemaking vs fewer bulletins/generic lette

9. Discuss the backfit appeal process (both plant-specific under NRCM 05 and recent examples of generic backfit appeals considered by CRGR).

TA8LE 3

Agenda for Event Reporting Workshops

Topic	Presentation/Discussion
NRC Criteria for Event Reporting - 50.72 - 50.73 - 50.9 - 73.71	Presentation by NRC and general discussio
Purpose and Use of Event Reporting - 50.72 - 50.73 - 50.9 - 73.71	Presentation by NRC and general discussio
Reporting Thresholds (Set too low?) - Safety Events - Safeguards Events	Presentation by NRC and general discussio
Necessary/Unnecessary Event Reports? - Emergency Diesel Actuation - 8WR Reactor Water Cleanup System Isolation - Control Room Isolation	Presentation by NRC and general discussio
Types of Events Being Reported - ESF Actuations - Tech Spec Shutdowns - Safety System Failures - Other	Presentation by NRC and general discussio
Actions Proposed to Eliminate Unnecessary Reporting	Presentation by NRC and general Discussio

NOTE: To facilitate the general discussions in the workshops of the la four agenda topics, there may be formal presenta-tions-(to be coordinated by NUMARC) of industry experiences views in those areas.

Supplement to Table 3

(Suggested Topics for Airing In Event Reporting Workshops)

1. How are written reports (i.e., LERs) and immediate notifications (50.72s) used by the NRC (both at headquarters and in the regions)? What is the NRC's events analysis process, and what are its object ives? How are generic events identified? What offices are involved providing followup of events, and is there any independent over sight within the NRC to ensure that initial reviews do not miss an importan lesson? What briefings and conference calls are routinely conducted that are the result of 50.72 notifications, and what is their purpose What NRC correspondence and initiatives result from the LERs and 50.7 reports and the analysis of those reports?

2. What is not being reported under 50.72 and 50.73 that the NRC expecte would be reported~ What are the most serious types of events that hav not been reported during the past few years, and did the regulations

require them to be reported? Based on six years of experience with t current rules, what reports does the NRC receive under 50.72 and 50.7 that are generally conceded to be unimportant? What areas of 50.72 a 50.73 are most often misinterpreted? How many serious events per yea are reported, and how many are not reported? What can be done to mak reports more complete and accurate? Can facsimile be used to transmi 50.72 reports?

3. What rulemaking has the NRC initiated to change 50.72 and 50.73? Wha steps are involved in these rulemakings, and how long will it take? What alternatives are available in the rulemaking process for making changes more quickly? Are there changes that can be made to the interpretation of the existing rules without actual changes to the rules, such as exemptions under 50.12 and 50.73(g)?

4. What was the motivation for modifying 50.72 and codifying 50.73 in 1984? What is the relationship between 50.73 and the NPRDS system? What lessons for the Vogtle IIT are applicable to the reporting process? What rulemakings to change the reporting requirements, othe than those already underway, are likely? What are the NRC's views on the BWR Owners' Group initiative to clarify reporting requirements?

DOCID 3719k

[New Query] [Table of Contents] [Previous Submittal] [Next Incoming]

426.
#DATE 16/03/1994
ACTS 2237
BINDER IR
#IEIR 50-275/94-08 AND 50-323/94-08
SUBJECT: NRC INSPECTION REPORT 50-275/94-08; 50-323/94-08
DATE OF INSPECTION: FEBRUARY 28, MARCH 1 AND 8, 1994
Dockets. 50-275
50-323

Licenses: DPR-80

Pacific Gas and Electric Company
ATTN: Mr. G. M. Rueger, Senior Vice President and General Manager
Nuclear Power Generation Business Unit
Nuclear Power Generation, B14A
77 Beale Street, Room 1451
P. O. Box 770000
San Francisco, California 94177

SUBJECT: NRC INSPECTION REPORT 50-275/94-08; 50-323/94-08

This refers to the inspection conducted by Mr. P. Narbut on February 28, March 1 and 8, 1994. The inspection included a review of activities authorized for your Diablo canine Nuclear Power Plant, Units 1 and 2. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report .

Areas examined during this inspection are described in the report. In followup to Inspection Rapport 50-275/93-36, 50-323/93-36, the inspection further reviewed PG&E's activities performed in response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," issued on July 18, 1989. The purpose of the inspection was to determine whether activities authorized by the license were conducted safely and in accordance with NRC requirements. within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observations by the inspector.

Based on the results of this inspection, three apparent violations were identified and are being considered for escalated enforcement action in accordance with the "General Statement of Policy and Procedure for NRC enforcement Actions" (Enforcement Policy), 10 CFR Part 2, Appendix C. The apparent valuations involved (1) the failure to implement adequate design control measures to assure that the specifications and procedures associated with the Component-Cooling Water Heat exchangers maintained the system design basis for maximum system temperature, (2) the failure to provide complete and accurate information tea the NRC regarding the results of the testing of these heat exchangers, and (3) the failure to identify the cause and take timely corrective action for the failure of CCW Heat Exchanger 1-2 to meet the test acceptance criteria for heat exchanger capacity on February 2, 1991. Accordingly, no Notice of Valuation is presently being issued for these inspection findings. In addition, please be advised that the number and characterization of apparent valuations described tn the enclosed inspection report may change as a result of further NRC
review.

An enforcement conference to discuss these apparent violations has been scheduled for March 23, 1994. This enforcement conference w;ll be open to public observation in accordance with the Commissions trial program as discussed in the enclosed Federal Register notice (Enclosure 2). The decision to hold an

enforcement conference does not mean that the NRC has determined that a violation has occurred or that enforcement action will be taken. The purposes of this conference are to discuss the apparent violations, their causes and safety significance; to provide an the opportunity to point out any errors in our inspection report; and to provide an opportunity for you to present your proposed corrective actions. In addition, this is an opportunity for you to provide any information concerning your perspectives on 1) the severity of the valuations, 2) the application of the factors that the NRC considers when it determines the amount of a civil penalty that may be assessed in accordance with Section VI.B.2 of the Enforcement Policy, and 3) any Other application of the Enforcement Policy to this case, including the exercise of discretion in accordance with Section VII. You will be advised by separate correspondence of the results of our deliberations on this matter. No response regarding these apparent violations is required at this time.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Ram.

Sincerely,

S. A. Richards, Acting Director
Division of Reactor Safety and Projects

enclosures:
1. Inspection Report 50-275/94-08; 50-323/94-0
2. Federal Register Gnats

cc w/enclosures:

Dr. Richard Ferguson, Energy Chair, Sierra Club California
Ms. Nancy Culver, San Luis Obispo Mothers for Peace
Ms. Jacqueline C. Wheeler Managing Editor, The County Telegram Tribune Chairman,
San Luis Obispo County Board of Supervisors
Mr. Truman Burns, California Public Utilities Commission
Mr. Robert Kinosian, California Public Utilities Commission
Robert R. Wellington, Esq., Diablo Canyon Independent Safety Committee
Mr. Steve Hsu, Radiologic Health Branch, State Department of Health Services
Mr. Peter H. Kaufman, Deputy Attorney General, State of California
Christopher J. Warner, Esq , PG&E
Mr. John Townsend, Vice President and Plant Manager, Diablo Canyon

U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Inspection Report: 50-275/94-08; 50-323/94-08

Operating License: DPR-80 and DPR-82

Licensee: Pacific Gas and Electric Company
Nuclear Power Generation, B14A
77 Beale Street, Room 1451
P. O. Box 770000
San Francisco, California 94177

Facility Name: Diablo Canyon Units 1 and 2

Inspection at: PG&E Corporate Offices
333 Market Strict
San Francisco, California 94177

Inspection Conducted: February 28, March 1 and 8, 1994

Inspector: P. Narbut, Regional Team Leader

Approved by: C. A. VanDenburgh 3/16/94
Acting Deputy Director
Division of Reactor Safety & Projects

Inspection Summary:

Areas Inspected (Units 1 and 2): Routine announced regional Inspection of PG&E's activities performed in response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," issued on July 18, 1989. The inspection failed up the unresolved items identified in NRC Inspection Report 50-275, 50-323/93-36. Temporary Instruction (TI) 2515/118 and Inspection Procedure 405000 were used as guidance during this inspection.

Safety Issues Management System (SIMS) Items: N~ne

Results (Units 1 and 2): Three apparent violations were identified involving:

o The failure to implement adequate design control measures to assure that the specifications and procedures associated with the Component Cooling Water Heat Exchangers maintained tho system design basis for maximum system temperature (Section 2).

o The failure to provide complete and accurate information to the NRC regarding the results of the testing of these heat exchangers (Section 3.2)

o The failure to ldentify the cause and take timely corrective action for the failure of the CCW Heat Exchanger 1-2 tea meet the test acceptance criteria for heat exchanger capacity on February 2, 1991 (Section 3.6).

Summary of Inspection Findings:

o Apparent Violation 50-275/94-08-01 was opened.

o Apparent Violation 50-275/94-08-02 was opened.

o Apparent Violation 50-275/94-08-03 was opened.

o Followup Item 50-275/94-08-04 was opened.

o Followup Item 50-275/93-36-01 was closed.

o Unresolved Item 50-275/93-36-02 was closed.

o Unresolved Item 50-275/93-36- 03 was closed.

- o Unresolved Item 50-275/93-36- 04 was closed.
- o Followup Item 50-275/93-36-05 was closed.
- o Unresolved Item 50-275/93-36- 06 was closed.
- o Unresolved Item 50-275/93-36- 07 was closed
- o Followup Item 50-275/93-36-08 was closed

Attachments:

- o Persons Contacted and Exit Meeting

DETAILS

1. BACKGROUND

The NRC issued Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," on July 18, 1989. The generic letter described recurring industry problems with the service water systems at nuclear power plants. Service water systems are important to plant safety as the ultimate heat sink following a design basis event. The generic letter recommended certain auctions to be taken by licensees and required that each licensee advise the NRC of the programs to be implemented in response to the generic letter recommendations. PG&E Letter No. DCL-90-027, dated January 26, 1990, provided PG&E's response to the generic letter and committed to perform certain actions. PG&E Letter No. DCL-91-286, dated November 25, 1991, provided a supplemental response to the generic letter and reported the completion of the initial program actions

NRC Inspection Reports 50-275, 50-323/93-36 examined the licensee's actions taken in response to Generic Letter 89-13 The inspection report identified a number of unresolved and followup items regarding the adequacy of the licensee's actions taken in response to the generic letter, and requested that the licensee address the items in a written response to the NRC. The licensee provided a response to the inspection report in PG&E Letter No. DCL-94-037, dated February 15, 1994. The response addressed each of the inspection items and stated that there were instances in 1981 and 1990 when the Auxiliary Saltwater System (ASW) may not have been operable. The response stated that a supplemental response would be provided when the results of the past operability study were completed. The results of that past operability study were documented in Licensee Event Report (LER) 1-93-012-01, "Auxiliary Saltwater System Outside Design Basis Due to Fouling," dated March 8, 1994.

2. ASW OPERABILITY AND DESIGN BASIS

NRC Inspection Report 50-275/93-36; 50-323/93-36, dated January 12, 1994, found that the licensee's heat exchanger test results showed that one ASW heat exchanger did not meet the acceptance standards for minimum heat transfer capacity established by the system design requirements. This raised a concern regarding the operability of the ASW system which the licensee subsequently determined to be temporarily acceptable due to the called winter sea temperatures. Additionally, the test data appeared to contradict the licensee's statements to the NRC in their November 25, 1991, letter to the NRC regarding the acceptability of the test results.

ln addition, the inspector found that the licensee had not assured that the ASW system maintenance and surveillance controls were sufficient to assure system operability. Specifically, the licensee had high differential pressure limits on the heat exchangers which allowed macrofouling to a degree that would apparently exceed the manufacturer's tube plugging limit and significantly reduce the heat removal capacity.

This concern also affected the operability of the ASW system which the licensee subsequently determined to be temporarily acceptable due To the cold winter sea temperatures.

In general, the previous inspection concluded that the licensee had not developed a good engineering understanding of the effects of micro fouling, macro fouling, and heat exchanger differential pressure and had not implemented adequate operational controls to ensure system operability. This was considered a significant failing due to the high safety significance of the system and the number of opportunities the licensee had to address the issues. NRC concerns regarding system operability due to differential pressure had also been previously raised in NRC Inspection Report 50-275/88-11. The licensee responded to those concerns with assurances that the differential pressures were acceptable. Generic Letter 89-13 again focused attention On the issue of heat exchanger performance. The failed heat exchanger capacity test in 1991 should have initiated additional analysis and understanding, but did not. Finally, a QA surveillance in May 1993 raised the same heat exchanger performance issues, but did not result in an adequate technical response from the engineering organization.

In response to these concerns, taring the paired from December 1993 to March 1994, the licensee performed extensive calculations to assess the operability of the Auxiliary Saltwater (ASW) system taring the periods of high micro fouling and high macrofouling of the Component Cooling Water (CCW) heat exchangers. The results of those calculations were presented in PG&E Letter No. DCL-94-037, "Auxiliary Saltwater Operability," dated February 15, 1994; and Licensee Event Report (LER) 1-93-012-01, "Auxiliary Saltwater System Outside Design Basis Due to Failing," dated March 8, 1994. The letter concluded that the ASW system was operable and capable of meeting its design basis for future operation. The LER also concluded that the ASW system had been operable, but not within its design basis rawer past operating periods. The licensee determined that the ability of the ASW system to meet its design basis was assured subsequent to the initiation of continuous chlorination of the system in September and November 1992 for Units 1 and 2 respectively.

During this inspection, the inspector reviewed Calculation No. M-963, Revision 0, File 140.061, dated March 7, 1994, which demonstrated the ASW system's past operability. rho calculation was very complex, in that several sets of cases and assumptions were used by Westinghouse and the licensee's technical staff to seaport their conclusions. Westinghouse used file cases and the licensee used five cases with a variety of subsets. The cases all had variances and did not correlate on a one-for-one basis. Nonetheless, the licensee was able to demonstrate the basis of their conclusions using the calculations. However, the inspector noted that the licensee's determination of operability was based on the following four facts:

o First, the calculations depended on the 1991 heat exchanger capacity test results for the tests done in response to Generic Letter 89-13. As discussed in Inspection Report 50-275, 50-323/93-36, those tests were not well controlled and the microfouling and macrofouling conditions were not known and had to be later inferred by the licensee. The licensee has committed to perform additional tests to confirm the performance inferred by the tests.

o Second, the licensee appeared to essentially remove the margin in the calculations. For example, the licensee took advantage of a two percent tube plugging allowance provided by the manufacturer to increase the baseline heat removal capacity by two percent. Likewise, the calculations used actual ocean temperatures, rather than higher design basis ocean temperatures. Similarly, actual versus design values were used for containment initial temperature, reactor power, water temperature in the Refueling Water Storage Tank, and other parameters. This technical approach appeared credible to the inspector for assessing past conditions, but left little of the conservative margin usually pressured for calculational uncertainties in predictions of performance.

o Third, the licensee took credit for operator auctions which they considered credible at the time, but which were not ln all cases part of the Emergency Operating Procedures (EOPs). Nevertheless, the licensee's assumptions appeared credible to the inspector.

o Fourth, the study was performed using the licensing basis model for mass and energy release which did not predict as severe conditions as the newer mass and energy release medical. The licensee made an approximate correction for this difference

The calculations concluded that no Final Safety Analysis Report (FSAR) design bases would have been exceeded during the injection phase of an accident. However, the calculation showed that later in the accident scenario during the recirculation phase, the Component Cooling Water (CCW) temperature would have exceeded the FSAR design basis peak temperature of 132 degrees Fahrenheit and would have exceeded 120 degrees for longer than the 20 minutes allowed by the FSAR design basis under the worst case conditions identified by the licensee to have actually occurred in the past The calculation showed a range of results with temperatures up to a peak of about 139 degrees and times above 120 degrees of abate 33 minutes. Tho licensee evaluated the Emergency Core Cooling System (ECCS) components affected by the increased CCW temperature and, after contact with Westinghouse and individual vendors, concluded that none of the components would have been adversely affected with the exception of the Centrifugal Charging Pumps (CCPs), which wad have experienced bearing failures. However, the licensee noted that the CCPs were not required during the recirculation phase and would have been secured by the operators in response to high bearing temperature alarms. The licensee also concluded that the Post Accident Sampling System (PASS) would have been inoperable due to the elevated CCW temperatures. However, alternate means of core damage assessment would have remained available.

The calculations also showed that, in approximate terms: (1) a clean heat exchanger had abate 20 percent margin, (2) a heat exchanger micro fouled to the usual amount currently encountered with continuous chlorination and macro fouled to 140 inches of differential pressure would have no margin, and (3) a heat exchanger with the current typical amounts of microfouling and macrofouling would be somewhere in between.

Although the licensee's evaluation demonstrated the operability of the ASW system under past actual operating conditions, the licensee concluded in PG&E Letter No. DCL-94-037, "Auxiliary Saltwater Operability," dated February 15, 1994; and Licensee

Event Report (LER) 1-93-012-01, "Auxiliary Saltwater System Outside Design Basis Due to Fouling," dated March 8, 1994, that the ASW system was not within its design basis for past operating periods. The licensee's failure to assure that the design basis as specified in the Final Safety Analysis Report (FSAR) was correctly translated into instructions and specifications for the operation and maintenance of the ASW system and the CCW heat exchangers, was considered an apparent violation (Apparent Violation 50-275/94-08-01).

3. OPEN ITEMS INSPECTION

The inspection examined the unresolved items and followup items identified in Inspection Report 50-275/93-36; 50-323/93-36 to determine their dispassion.

3.1 (Closed) Followup Item 50-275/93-36-01. Review of Design Basis

This item concerned the perception that the licensee had adopted a revised design basis which had not been reviewed by NRR. The licensee's response, PG&E Letter DCL-94-037, dated February 15, 1994, clarified that the design basis had not changed from that which was described in the Final Safety Analysis Report (FSAR). The families of acceptance curves in WCAP-12526, Revision 1, "Auxiliary Salt Water and Component Cooling Water Flow and Temperature Study for Diablo Canyon Units 1 and 2," dated June 1992, were derived utilizing the proper design basis

3.2 (Closed) Unresolved Item 50-275/93-36-02 Failure to Previewed Complete and Accurate Information Regarding a Heat Exchanger Capacity Test

This unresolved item involved the adequacy of the results of a heat exchanger capacity test which had been performed on the Component Cooling Water heat exchangers. The licensee had reported to the NRC that the heat exchangers met their design heat rem Oval capacity; however, the test data showed that One of the four heat exchangers did not meet this capita.

Generic Letter 89-13 requested that licensees conduct a test program tn verify the heat transfer capability of all safety-related heat exchangers. In PG&E Letter DCL-90-027, dated January 26, 1990 the licensee explained that they would perform a One-time heat exchanger performance test to confirm the baseline heat transfer capability of the heat exchangers. In PG&E Letter DCL--91-286, dated November 25, 1991, the licensee reported that they had performed the heat exchanger capacity test and stated that "...the computer model predicted that the heat exchanger would remove the design basis heat load at design conditions."

The inspector reviewed the results of the One-time heat exchanger test. The test methods and results were described in Field Test Report 420DC-91.1156, Audibly Canyon Power Plant CCW Heat Exchanger Performance Tests Units 1 and 2,~ dated November 22, 1991. The test report showed that the computer prediction for Unit 1 Component Cooling Water Heat Exchanger 1-2 did not predict that the heat exchanger wad remove the design basis heat load. Rather, the test results showed the heat exchanger capacity to be at 98.7 percent of design.

The licensee subsequently concluded and reported in PG&E Letter No. DCL-94-037, dated February 15, 1994, that the test results for the heat exchanger did not meet the protected design basis heat transfer requirements using the computer program chosen at the time. The licensee concluded that the heat exchanger was fouled by an abnormal amount of microfouling at the time of the test. The licensee also concluded

that if a different, more commonly used, computer code had been used then the calculated test results would have been 101 percent of the design basis requirements vice 98.7 percent. The licensee stated in the February 1994 letter that they believed that their statement regarding test results in the November 1991 letter was accurate and complete based on guidance ln the generic letter and based on the inaccuracies of the testing methodology.

The inspector reviewed the guidance in the generic letter with the licensee and found only general discussions that indicated that the level of detail provided by licensee's should be sufficient to demonstrate the adequacy of their actions Therefore, the inspector concluded that the licensee failed to provide complete and accurate information to the NRC in regards to the CCW 1-2 heat exchanger's ability to meet the design basis heat load. This failure is considered an apparent violation (Apparent Violation 50-275/94-08-02).

3.3 (Closed) Unresolved Item 50-275/93- 36-03, Differential Pressure Limits for the CCW Heat Exchangers

This item involved the adequacy of the 140-inch differential pressure limit used by the licensee as an operational limit for macrofouling and heat exchanger operability. The inspect or was concerned that the licensee's basis for this operating limit was essentially engineering judgment, rather than analysis or some other technical basis The inspector's review developed a technical basis for a substantially lesser amount of differential pressure based on the manufacturer's tube plugging limit

The licensee subsequently performed calculations of the effects of tube blocking on heat exchanger differential pressure utilizing the current expected amounts of heat exchanger microfouling (i.e., slime). These calculations reflected the use of continuous chlorination which the licensee demonstrated had reduced the amount Of microfouling. The licensee then used the reduced amount of microfouling to increase the allowed amount of macrofouling.

The licensee concluded that the operational limit of 140 inches was appropriate. However, to achieve this conclusion the licensee performed flow testing in February 1994 and then projected the results to include

the more difficult conditions of low tide, cross-train flow configuration, and an Ocean temperature of 64 degrees. The results of that calculation (Calculation No. M-962, Revision 0) showed that a differential pressure of up to 134 inches (not 140 inches) could be tolerated and provided the necessary amount of flow for design basis cooling. This calculation was based on the limited 1991 heat capacity test results and showed that the 134 inch differential pressure was achieved with a total blockage of about 250 tubes. The licensee then used a qualitative assessment to judge that a value of 140 inches wad be an appropriate limit. This assessment was based on the Opinion that the blacked tubes would not be totally blocked but whaled allow some flow and cooling to occur. The inspector concurred with the licensee's observation that the heat exchanger tubes do not generally become fully blacked by the mussels and barnacles typically found in the heat exchangers.

The licensee attempted to correlate these calculational results with results from biomass surveys which had sometimes been done during heat exchanger cleanings. However, the data did not correlate well and showed a wide variance in the number of marine creatures removed at any given differential pressure. It was the opinion of the licensee's marine biologist that, the calculated number of blocked tubes (about 250) roughly agreed with the usual condition at 130 inches of differential pressure.

The inspector concluded that the licensee calculations demonstrated that the differential pressure limit of 140 inches was sufficient to provide design basis cooling if the amount of microfouling assumed and the heat exchanger capacity assumed were correct. However, the inspector noted that the calculations did not demonstrate that any significant margin existed in the 140 inch limit.

The licensee stated in PG&E Letter No. DCL-94-037, dated February 15, 1994, that they recognized the limitations of the calculational model. The letter also stated that additional functional tests of the heat exchangers would be performed during the 1994 refueling outages and that PG&E would reassess the 140 inch limit based on the test results.

3.4 (Closed) Unresolved Item 50-275/93- 36-04. Routine Inspection and Maintenance of the ASW System Piping

This item concerned the licensee's apparent failure to develop and implement a routine inspection program for ASW piping as committed in PG&E Letter DCL-90-027, dated January 26, 1990, and as stated as complete in PG&E Letter DCL-91-286, dated November 25, 1991.

Generic Letter 89-13 recommended that a rattan inspection and maintenance program for the service water system piping and components be established so that corrosion, erosion, coating failure, silting, and biofouling would not degrade the performance of the system. In PG&E Letter DCL-90-027, dated January 26, 1990, the licensee stated that they would develop a program and that procedures for a routine piping inspection and maintenance program for the ASW system would be established by the 1991 fourth refueling outages of Units 1 and 2. In PG&~E Letter DCL-91-286, dated November 25, 1991, the licensee stated that they had established a routine piping inspection and maintenance program.

The inspector had previously concluded that the inspection program had not been implemented as stated based on the apparent fact that the procedure for inspection had not been issued and the frequency of inspection had not been selected. During this inspection, the licensee stated that they considered that the inspection program had been implemented based on two open action items which documented their decision on frequency of the inspection and the intent to issue a permanent plant procedure based on their temporary procedure. Specifically, the licensee had previously provided the inspector a copy of open Action Request (AR) No. A0221696, dated March 6, 1991, which requested that the temporary inspection procedure be made a permanent plant procedure and that a regular inspection frequency be established. Additionally, the licensee provided AR A0245348, dated September 30, 1991, which had not been presented during the previous inspection. this action request was directed to the system engineer from the design engineer and requested that a frequency be established for the internal piping inspections. An electronic response, dated

November 22, 1991, stated that the frequency would be every fourth refueling outage, with the Option to change the frequency based on experience.

Based on the above, the inspector considered that the licensee had satisfactorily demonstrated that they had determined the frequency of the inspection and had an internal action item to prepare a permanent plant procedure to perform the inspection. Therefore, the inspector considered that the licensee's statement to the NRC in letter DCL-91-286, dated November 25, 1991, that "The procedures and inspections for this program have been established and were performed during the Units 1 and 2 fourth refueling outages, and frequencies of performance were established or confirmed in response to the observations during these outages." was sufficiently complete and accurate. This unresolved item is considered closed.

3.5 (Closed) Followup Item 50-275/93- 36-05. Confirmation of Licensing Basis of the ASW System

This item concerned an assessment of the need for the licensee to reperform a review of the adequacy of their design bases for the ASW system which had been performed for Generic Letter 89-13. The question arose from the inspector's questions regarding the adequacy of the licensee's understanding of their macrofouling and micro fouling limits and also from the licensee's quality assurance audit findings regarding pump runout conditions.

In PG&E Letter No. DCL-94-037, dated February 15, 1994, the licensee stated that additional testing of the CCW heat exchangers would be done in 1994 to assure that the heat exchangers met their design bases. Additionally, the letter stated that a team (consisting of operations, quality services, maintenance, Westinghouse and engineering) would thoroughly and critically review the ASW, CCW, and interfacing systems by the end of 1994. The letter also stated that the design basis document wad be revised appropriately. Based on the licensee's committed actions, this item is considered closed.

3.6 (Closed) Unresolved Item 50-275/93- 36-06. Failure to take Timely Action

This item concerned the licensee's slow resolution of problems adverse to quality. The licensee had identified that CCW heat exchanger 1-2 failed to meet its test acceptance criteria in a test conducted on February 2, 1991. The test failure was documented in Field Test Report 420DC-91.1156, "Diablo Canyon Power Plant CCW Heat Exchanger Performance Tests Units 1 and 2," dated November 22, 1991. The test failure was also identified during a Quality Assurance (QA) surveillance and documented on Action Request No. A03066715, dated May 10, 1993. The effect of the test failure on ASW system operability was not resolved until after the issues were identified by the NRC inspector in NRC Inspection Report 50-275/93-36; 50-323/93-36.

As previously discussed in Section 2.0 of this report, the licensee concluded that the ASW system had been operable, but outside its design basis for periods prior to September 1992 when canteens chlorination of the system was initiated. These conclusions were provided to the NRC in a 10 CFR 50.72 report made on December 30, 1993. The licensee also documented their conclusions in PG&E Letter DCL-94-049, dated March 8, 1994, which provided Licensee Event Report 1-93.012-01, "Auxiliary Saltwater System Outside Design Basis Due to Fouling." The report concluded that on August 23, 1990, and perhaps dates prior to and subsequent to that dale, the CCW heat exchangers for both units may have had sufficient following to have precluded the systems from meeting their design bases.

10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states that conditions adverse to quality are promptly identified and corrected. The criterion further states that, in the case of significant conditions adverse to quality, the cause of the condition should be determined.

The failure of the ASW system to have met its design basis is considered a significant condition adverse to quality. Subsequent to the CCW heat exchanger 1-2 capacity test failure on February 1, 1991, the licensee failed to promptly identify, correct, or fully determine the cause of the test failure. The determination was made in February 1994 in response to Inspection Report 50-275/93-36; 50-323/93-36.

The failure to identify the cause and implement timely corrective actions for this condition adverse to quality is considered an apparent violation (Apparent Violation 50-275/94-03).

3.7 (Closed) Unresolved Item 50-275/93- 36-07, Use of a Computer Code that had not been Validated

This item concerned the licensee's use of a computer code which had not been validated for accuracy. The code was used to calculate the heat exchanger capacity for the CCW heat exchanger capacity tests done ln response to Generic Letter 89-13. During this inspection, the licensee demonstrated that the results of the code used were conservative compared tea the code generally utilized by the industry to analyze heat exchanger capacity. additionally, the licensee demonstrated that the NRC had indicated, in Generic Letter 89-13 Supplement 1, "Questions and Answers," that it was willing to accept off-the- shelf software

3.8 (Closed) Followup Item 50-275/93-36-08. Scaling of Heat Exchanger Tubes

This item concerned scaling on the inner diameter of the CCW heat exchanger tubes. The scaling was located only at the outlet end of the heat exchanger in the tube sheet area. The system engineer had stated that the cause of the scaling was deposits from seawater caused by the impressed voltage system for cathodic protection of the ASW piping. The system engineer had further stated that the scaling was deposited for a short length and would gnat affect the available heat transfer area or tube fouling factor. The inspector was concerned that the scaling could cause the tubes to plug at the outlet end, which would not be detected by the periodic cleaning and inspection of the inlet end. The system engineer had indicated that such tube end plugging had gnat been seen and that only a small amount of scaling had been seen. The inspector noted that the system engineer interviewed at the time of the December 1993 inspection was new and was gnat the engineer who had performed the inspections of the heat exchangers.

During this inspection, the inspector determined by a review of past heat exchanger records frame April 1992, that heat exchanger scaling had proceeded to such an extent in CCW heat exchanger 2-1 that 7 of the 20 tubes amend by a video camera, had become completely blocked at the outlet end, and 3 additional tubes were partially blocked. This heat exchanger had not had the normal outage maintenance of tube scraping performed during the previous refueling outage due to an outage management decision according to the licensee. The lack of tube scraping in the previous outage was attributed as the cause of the observed tube blockage.

The inspector noted that the licensee's response tea the December inspection provided in PG&E Letter DCL-94-037, dated February 15, 1994, stated that the licensee considered that there was a low potential for tube plugging and that tube plugging would be detected by heat exchanger differential pressure. The inspector noted that this statement appeared to contradict the inspection data for CCW Heat Exchanger 2-1. In explanation, the licensee stated that the statement regarding the low probability of tube plugging was made reflecting the revised maintenance policy which required tube scrapping each outage.

The February 1994 response also stated that the licensee would change their monthly surveillance procedure to add trending of the differential pressure across the heat exchanger. The inspector noted that differential pressure trending would not provide data on the rate and degree of scale buildup. It appeared to the inspector that the licensee had assumed, rather than demonstrated, that scraping once an outage would prevent tube blockage Factors such as the level of voltage used for cathodic protection were not assessed for their affect on the rate of scale buildup. At the exit interview, the licensee committed to trend the rate of scale buildup in the CCW heat exchangers and to assess the adequacy Of the impressed voltage.

4. INSTRUMENT LINE SILTING

During testing conducted in February 1994 the licensee found that silting of the differential pressure instrument lines had occurred. The silting caused errors in the indicated differential pressure across the heat exchanger estimated by the licensee to be up to 25 inches. The licensee stated that they would establish a regular cleaning maintenance task to preclude repetition. The licensee had not assessed the significance of the silting. This is a followup item (Followup Item 50-275/94-08-04).

ATTACHMENT

PERSONS CONTACTED

Pacific Gas and Electric Company

+*W. H Fujimoto, Vice President, Nuclear Technical Services
M. J. Angus, Manager, Technical and Support Services
J. A. Sexton, Manager, Nuclear Regulatory Services
+*T. L. Grebel, Supervisor, Regulatory Compliance Supervisor
*M. E. Leppke, Assistant Manager, Technical and Support Services
K. S. Smith, Mechanical Engineer, Nuclear Engineering Services
C. P. Rhodes, Senior Engineer
G. L. Starnes, Mechanical Engineer, Technical and Ecological Services
R. B. Clark, Director of Nuclear Engineering Services
J. Kelly, Mechanical Group Leader nuclear Engineering Services
J. R. del Mazo, Director of Mechanical Engineering

Contractor for Pacific Gas and Electric Company

R. J. Bell, Director of Engineering, Heat Exchanger Systems, Inc.
F. L. Steinert, Senior Scientist, Aquatic Systemize Inc.

*Denotes those attending the exit interview on March 1, 1994.
+*Denotes those attending the exit interview on March 8, 1994.

EXIT MEETING

An exit meeting was conducted on March 1 and March 8, 1994, with the licensee representatives identified above. The inspector summarized the scope and findings of the inspection as described in this report. The licensee did not identify as preparatory any of the materials reviewed by or discussed with the inspectors during this inspection with the exception of some of the Westinghouse calculations which were marked as "Proprietary Class 2."

440.
#DATE 14/07/1994
ACTS 2237
BINDER IR
#IEIR 50-275/94-08 AND 50-323/94-08
SUBJECT: NOTICE OF VIOLATION
(NRC Inspection Report No. 50-275/94-08, 50-323/94-08)
DATE OF INSPECTION: FEBRUARY 28, MARCH 1 AND 8, 1994

Dockets: 50-275
50-323
Licenses: DPR-80
DPR-82

EA 94-056

Pacific Gas and Electric Company
Nuclear Power Generation, B14A
ATTN: Gregory M. Rueger, Senior Vice
President and General Manager
Nuclear Power Generation Bus. Unit
77 Beale Street, Room 1451
P.O. Box 770000
San Francisco, California 94177

SUBJECT: NOTICE OF VIOLATION
(NRC Inspection Report No. 50-275/94-08, 50-323/94-08)

This refers to the inspection conducted by Mr. Paul P. Narbut on February 28, March 1 and 8, 1994, at the offices of Pacific Gas and Electric Company (PG&E). The results of this inspection were documented in the subject NRC inspection report, transmitted to you on March 16, 1994, and were discussed during an enforcement conference held in Walnut Creek on March 23, 1994. The enforcement conference summary was transmitted to you on April 20, 1994.

The enclosed Notice of Violation (Notice) describes a significant violation involving the failure of your engineering staff to fully recognize or correct operational deficiencies in the Auxiliary Saltwater (ASW) System, despite several opportunities to recognize the existence of these deficiencies. The root cause of this violation appears to involve inadequate licensee attention to engineering practices that ensure clear definition of test acceptance criteria for the ASW System, and to timely resolution of observed ASW System, and to timely resolution of observed ASW System test problems. As reflected in the subject NRC inspection report, the NRC also considered separate citations for failure to implement adequate design control measures to assure that ASW specifications and procedures were adequate to properly limit maximum Component Cooling Water (CCW) temperature during a design basis accident, and for failure to provide complete and accurate information to the NRC regarding the results of ASW system testing. However, upon further consideration, we have decided that each of these failures was a direct consequence of the poor engineering work that resulted in your failure to take appropriate corrective action, and that separate citations are not warranted.

The NRC is concerned that PG&E, a licensee with a demonstrated record of strong engineering performance, would allow the poor engineering practices that contributed to the violation in this case. We are even more concerned about PG&E's failure to properly exploit several opportunities to have identified and corrected this Problem prior to NRC involvement. This is not the first time that the NRC has addressed

ASW system design concerns at Diablo Canyon. NRC Inspection Report 50-275/88-11, dated May 28, 1988, identified ASW system design basis concerns, to which PG&E Letter DCL-88-215, dated September 13, 1988, responded that the system had ample design margin, and that maintenance practices would prevent significant fouling or blockage. Likewise, NRC Inspection Report 50-275/89-01, dated February 28, 1989, identified violations concerning ASW system design basis implementation deficiencies. Your response to the violations stated that development of a design basis document program would ensure that the design bases were properly implemented.

Prompted by service water system problems at several reactor plants, the NRC issued Generic Letter 89-13, "Service Water System Problems Affecting Safety--Related Equipment," in July 1989. The Generic Letter encouraged licensees to ensure that the ultimate heat sink for safety-related systems was properly maintained to assure its ability to reject design, basis heat loads under accident conditions. PG&E responded in Letter DCL-90-027, dated January 26, 1990, and DCL-91-286, dated November 25, 1991, stating that PG&E tests had demonstrated that the ASW system would remove the design basis heat load under design conditions.

Despite PG&E assurances of ASW system design margin, the NRC determined that CCW heat exchanger 1-2 failed to demonstrate ability to remove the design basis heat load during a heat exchanger capacity test performed in February 1991. The NRC also determined that PG&E had failed to properly identify the cause or to take timely corrective action following the February 1991 CCW heat exchanger test failure. Further, a May 1993 PG&E Quality Assurance (QA) surveillance report and July 1993 QA audit report had addressed the heat exchanger test failure, but PG&E engineering personnel again failed to promptly respond to identified problems, this time by failing to properly evaluate or resolve the QA findings, and QA did not force the issue. PG&E's inadequate followup on the QA findings represents an additional, significant missed opportunity to have identified and corrected the violation which is now being cited by the NRC.

In response to the NRC inspection, PG&E performed an evaluation which concluded that the February 1991 CCW heat exchanger test failure was due to heat exchanger fouling. In response to the inspection, PG&E also performed an operability evaluation using actual plant conditions which existed from 1984 to 1992, concluding that any past ASW system failures to comply with the design bases were of limited duration and consequence The PG&E evaluation and conclusions were documented in PG&E Letter DCL-94-037, dated February 15, 1994, and Letter DCL-94-049, dated March 8, 1994.

These failures to correct conditions adverse to quality in this particular instance appear to constitute a breakdown in the control of the design and operational activities for the ASW system as described above. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy), 10 CFR Part 2, Appendix C, this matter has been classified as a Severity Level III violation. Under the Enforcement Policy, a civil penalty is considered for a Severity Level III violation However, after consultation with the Director, Office of Enforcements and the Deputy Executive Director for Nuclear Reactor Regulation, Regional Operations, and Research, I have decided that a civil penalty will not be proposed in this case after considering the mitigation and escalation factors in the Enforcement Policy as described below.

The base civil penalty for a Severity Level III violation was escalated by 50% for identification, since the violation was identified as a result of an NRC inspection. The civil penalty was mitigated by 50% for corrective action, based on your comprehensive corrective actions, including additional ASW system testing, increased system cleaning frequency, and a commitment to review containment heat removal systems to assure that they meet their design bases, and commitments for improved procedures for defining test acceptance criteria and for timely resolution of QA findings.

The civil penalty was mitigated by an additional 100% in recognition of PG&E's history of superior performance in the areas of engineering and quality assurance. We considered escalation for prior opportunity since, as described earlier, PG&E had several opportunities to identify and correct the violation. However, since these missed opportunities where in effect, the primary reason for the corrective action violation, we have determined that escalation under this factor is not appropriate in this case. The

other adjustment factors in the Enforcement Policy were considered, and no further adjustment to the base civil penalty was warranted. Based on the above, the civil penalty was fully mitigated.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

The responses directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96-511.

Sincerely,

L. J. Callan
Regional Administrator

Enclosure: Notice of Violation

cc w/enclosure:
Sierra Club California
ATTN: Dr. Richard Ferguson
Energy Chair
6715 Rocky Canyon
Creston, California 93432

San Luis Obispo
Mothers for Peace
ATTN: Ms. Nancy Culver
P.O. Box 164
Pismo Beach, California 93448

Ms. Jacquelyn C. Wheeler
P.0. Box 164
Pismo Beach, California 93448

The County Telegram Tribune
ATTN: Managing Editor
1321 Johnson Avenue
P.O. Box 112
San Luis Obispo, California 93406

San Luis Obispo County Board of
Supervisors
ATTN: Chairman
Room 370
County Government Center
San Luis Obispo, California 93408

California Public Utilities Commission

ATTN: Mr. Truman Burns\Mr. Robert Kinosian
505 Van Ness, Rm. 4102
San Francisco, California 94102

Diablo Canyon Independent Safety Committee
ATTN: Robert R. Wellington, Esq.
Legal Counsel
857 Cass Street, Suite D
Monterey, California 93940

Radiologic Health Branch
State Department of Health Services
ATTN: Mr. Steve Hsu
P.0. Box 942732
Sacramento, California 94234

State of California
ATTN: Mr. Peter H. Kaufman
Deputy Attorney General
110 West A Street, Suite 700
San Diego, California 92101

Pacific Gas and Electric Company
ATTN: Christopher J. Warner, Esq.
P.O. Box 7442
San Francisco, California 94120

Diablo Canyon Nuclear Power Plant
ATTN: John Townsend, Vice President
and Plant Manager
P.O. Box 56
Avila Beach, California 93424

NOTICE OF VIOLATION

Pacific Gas and Electric Company Dockets: 50-275, 50-323
Diablo Canyon Nuclear Plant Licenses: DPR-80, DPR-82
EA 94-056

During an NRC inspection conducted on February 28, March 1, and March 8, 1994, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C, the particular violation is set forth below:

10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, that macros shall be established to assure that conditions adverse to quality, such as failures and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

Contrary to the above, during a test conducted on February 2, 1991, Component Cooling Water (CCW) Heat Exchanger 1-2 failed to demonstrate the ability to remove the design basis heat load, as documented in Field Test Report 420DC-91.1156, and the measures established by the licensee did not

assure that this significant condition adverse to quality was promptly corrected or that the cause of the condition was determined. Despite this condition being recognized in the above referenced Field Test Report dated November 22, 1991, in Action Request No. A0306715 dated May 10, 1993, and in Quality Assurance report SQA-93-0031 dated July 28, 1993, the licensee did not take prompt action to correct this condition, to assess the impact of fouling on heat exchanger performance or to determine the significance of this condition with respect to the operability of the Auxiliary Saltwater System (ASW).

This is a Severity Level III violation (Supplement I).

Pursuant to the provisions of 10 CFR 2.201, Pacific Gas and Electric Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555 with copies to the Regional Administrator, Region IV, and the Director, Walnut Creek Field Office, Region IV, and a copy to the NRC Resident Inspector at Diablo Canyon, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued to show cause why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time. Under the authority of Section 182 of the Act, 42 U.S.C. 2232, this response shall be submitted under oath or affirmation.

Dated at Arlington, Texas
this 14th day of July 1994

437.
#DATE 07/07/1994
ACTS 2237
BINDER IR
#IEIR 50-275/94-21 AND 50-323/94-21
SUBJECT: NRC INSPECTION REPORT 50-275/94-21; 50-323/94-21
DATE OF INSPECTION: MAY 24, 1994

Dockets: 50-275
50-323
Licenses: DPR-80
DPR-82

Pacific Gas and Electric Company
Nuclear Power Generation, B14A
ATTN: Gregory M. Rueger, Senior Vice
President and General Manager
Nuclear Power Generation Bus. Unit
77 Beale Street, Room 1451
P.O. Box 770000
San Francisco, California 94177

SUBJECT: NRC INSPECTION REPORT 50-275/94-21; 50-323/94-21

This refers to the inspection conducted by P. Narbut of this office on May 24, 1994. The inspection included a review of activities authorized for your Diablo Canyon Nuclear Power Plant, Units 1 and 2, facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress. The results of this inspection are documented on Pack 1 in the enclosed report.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room.

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

Thomas P. Gwynn, Director
Division of Reactor Safety

Enclosure:
Appendix - NRC Inspection Report

50-275/94-21; 50-323/94-21 w/Attachment

cc w/enclosure:
Sierra Club California
ATTN: or. Richard Ferguson

Energy Chair
6715 Rocky Canyon
Creston, California 93432

San Luis Obispo
Mothers for Peace
ATTN: Ms. Nancy Culver
P.O. Box 164
Pismo Beach, California 93448

Ms. Jacqueline C. Wheeler
P.O. Box 164
Pismo Beach, California 93448

The County Telegram Tribune
ATTN: Managing Editor
1321 Johnson Avenue
P.O. Box 112
San Luis Obispo, California 93406

San Luis Obispo County Board of
Supervisors
ATTN: Chairman
Room 370
County & Government Center
San Luis Obispo, California 93408

California Public Utilities Commission
ATTN: Mr. Truman Burns\Mr. Robert Kinosian
505 Van Ness, Rm. 4102
San Francisco, California 94102

Diablo Canyon Independent Safety Committee
Attn: Robert R. Wellington, Esq.
Legal Counsel
857 Cass Street, Suite D
Monterey, California 93940

Radiologic Health Branch
State Department of Health Services
ATTN: Mr. Steve Hsu
P.O. Box 942732
Sacramento, California 94234

State of California
ATTN: Mr. Peter H. Kaufman
Deputy Attorney General
110 West A Street, Suite 700
San Diego, California 92101

Pacific Gas and Electric Company
ATTN: Christopher J. Warner, Esq.
P.0. Box 7442
San Francisco, California 94120

Diablo Canyon Nuclear Power Plant
ATTN: John Townsend, Vice President
and Plant Manager
P.O. Box 56
Avila Beach, California 93424

APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-275/94-21
50-323/94-21

Licenses: DPR-80
DPR-82

Licensee: Pacific Gas and Electric Company (PG&E)
77 Beale Street, Room 1451
P.O. Box 770000
San Francisco, California

Facility Name: Diablo Canyon Nuclear Power Plant, Units 1 and 2

Inspection At: Pacific Gas & Electric Corporate offices
333 Market Street
San Francisco, California 94177

Inspection Conducted: May 24, 1994

Inspector: P. Narbut, Regional Team Leader, Division of Reactor Safety

Approved: A. T.Howell, Deputy Director 7/6/94
Division of Reactor Safety Date

Inspection Summary:

Areas Inspected (Units 1 and 2): Routine, announced inspection of PG&E's activities performed in response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," issued on July 18, 1989. The inspection examined some additional questions that had arisen subsequent to the inspection reported in NRC Inspection Report 50-275/94-08; 50-323/94-08. Temporary Instruction (TI) 2515/118 and Inspection Procedure 40500 were used as guidance during this inspection.

Results (Units 1 and 2): The licensee satisfactorily resolved the concerns developed subsequent to the issuance of NRC Inspection Report 50-275/94-08; 50-323/94-08.

Attachment:

- Attachment - Persons Contacted and Exit Meeting

DETAILS

1 FOLLOWUP QUESTIONS REGARDING AUXILIARY SALT WATER SYSTEM OPERABILITY

1.1 Background

The NRC issued Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," on July 18, 1989. The generic letter described recurring industry problems with the service water systems at nuclear power plants. Service water systems are important to plant safety as the ultimate heat sink following a design basis event. The generic letter recommended certain actions tea be taken by licensees and required that each licensee advise the NRC of the programs to be implemented in response to the generic letter recommendations. PG&E Letter No. DCL-90-027, dated January 26, 1990, provided PG&E's response to the generic letter and committed to perform certain actions. PG&E Letter No. DCL-91-286, dated November 25, 1991, provided a supplemental response to the generic letter and reported the completion of the initial program actions.

NRC Inspection Report 50-275/93-36; 50-323/93-36 examined the licensee's actions taken in response to Generic Letter 89-13. The inspection report identified a number of unresolved and followup items regarding the adequacy of the licensee's actions taken in response to the generic letter, and requested that the licensee address the items in a written response to the NRC. The licensee provided a response to the inspection report in PG&E Letter No. DCL -94-037, dated February 15, 1994. The response addressed each of the inspection items and stated that there were instances in 1987 and 1990 when the Auxiliary Saltwater System (ASW) may not have been operable. The response also stated that a supplemental response would be provided when the results of the past operability study were completed. The results of that past operability study were documented in Licensee Event Report (LER) 1-93-012-01, "Auxiliary Saltwater System Outside Design Basis Due to Fouling," dated March 8, 1994.

NRC Inspection Report 50-275/94-08; 50-323/94-08 followed up the issues identified in NRC Inspection Report 50-275/93-36; 50-323/93-36, closed the majority of the unresolved items, and described three apparent violations to be addressed by separate correspondence.

This inspection examined several concerns regarding the licensee's studies of ASW operability which had arisen during the period subsequent to the issuance of NRC Inspection Report 50-275/94-08; 50-323/94-08.

1.2 Case Studies with Low Flows

The licensee had performed a number of case studies to demonstrate ASW system operability. The cases were numbered "A" to "S" and were described as evolutionary in that the cases evolved into the cases the licensee considered to be realistic representations of the relevant plant parameters in effect during the periods of high micro fouling and high macro fouling. Some of the case studies which the license performed

(Cases C, G, J, and L) had flows in the 9000-10,000 pm range, whereas the cases the licensee considered to be most representative (Cases O and P) had flows in the 11,000 spin range. The concern arose as to why the lower flow cases weren't utilized.

The licensee demonstrated that the lower flow cases were based on the lowest flow recorded for ASW flow Refueling cycle 4. This value was 11,008 spin which occurred on January 5, 1990. The flow value was then projected downward to account for low tide, a crosstie configuration, instrument error, and maximum macro fouling differential pressure. The result was a flow of 9886 spin used in Cases G and L and a slightly higher flow of 9968 spin in Cases C and J due to a small error in the tide calculation.

The licensee utilized flows of 11,676 and 11,196 spin for Cases O and P respectively. Case O was the study of the period of high micro fouling in August 1990 and Case P was the period of high macro fouling in 1987. The licensee utilized what they considered to be more realistic flow data (rather than the minimum recorded flow) which was an average flow derived from flow data from their quarterly ASME pump performance tests. The licensee did not use data from their monthly tests because the statistical deviations for that data were higher than the deviations for the quarterly test data. This was not a conservative decision since the monthly data was generally slightly lower than the quarterly data. Both data sets are derived from the same unbar flow instruments. however, the inspector noted that the licensee's study of data deviation appeared to support their decision that the quarterly data was more accurate. During the inspection, the licensee performed an estimate that use of the more conservative monthly data would have resulted in higher calculated CCW temperatures of only O.15-0.20 if, which was not significant to the conclusions of the operability study.

Additionally the licensee corrected the raw unbar averages upward by about 500 spin, or about 4.5 percent of the total flow, based on recently developed flow measurement correlation data which showed that the unbar data was low compared to actual flow as measured by more accurate dye dilution flow measurement methods. The inspector concluded that although this could be viewed as another non-conservative approach, the licensee had compensated by utilizing more conservative time temperature blocks or envelopes in their equipment operability evaluations. These time temperature blocks conservatively enveloped the detailed time temperature curves which resulted from the licensee's calculations, and were used to evaluate the increased temperature effects on equipment operability.

The inspector therefore concluded that the Case O and P flow data used for the licensee's operability analysis was reasonable. The flow data was not as conservative as it could have been but the use of a more conservative approach would not have affected the ultimate conclusion that the system had been operable but not within design basis during the periods Of high micro fouling and high macro fouling.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

*M. Angus, Manager, Technical and Support Services
*T. Grabble, Supervisor, Regulatory Compliance Supervisor
*J. Kelly, Mechanical Group Leader, Nuclear Engineering Services
*M. Leppke, Assistant Manager, Technical and Support Services
*J. Sexton, Manager, Nuclear Regulatory Services
K. Smith, Mechanical Engineer, Nuclear Engineering Services
G. Starnes. Mechanical Engineer, Technical and Ecological Services

1.2 Contractor for Pacific Gas and Electric Company

F. L. Steinert, Senior Scientist, Aquatic Systems Inc.

*Denotes those attending the exit interview on May 24, 1994.

2 EXIT MEETING

An exit meeting was conducted on May 24, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

July 18, 1989

TO: ALL HOLDERS OF OPERATING LICENSES OR CONSTRUCTION PERMITS FOR NUCLEAR POWER PLANTS

SUBJECT: SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT (GENERIC LETTER 89-13)

Purpose:

Nuclear power plant facilities of licensees and applicants must meet the minimum requirements of the General Design Criteria (GDC) in 10 CFR Part 50, Appendix A. In particular, "GDC 44--Cooling Water" requires provision of a system (here called the service water system) "to transfer heat from structures, systems, and components important to safety to an ultimate heat sink" (UHS). "GDC 45--Inspection of Cooling Water System" requires the system design "to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system." "GDC 46--Testing of Cooling Water System" requires the design "to permit appropriate periodic pressure and functional testing."

In addition, nuclear power plant facilities of licensees and applicants must meet the minimum requirements for quality assurance in 10 CFR Part 50, Appendix B. In particular, Section XI, "Test Control," requires that "a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents."

Recent operating experience and studies have led the NRC to question the compliance of the service water systems in the nuclear power plants of licensees and applicants with these GDC and quality assurance requirements. Therefore, this Generic Letter is being issued to require licensees and applicants to supply information about their respective service water systems to assure the NRC of such compliance and to confirm that the safety functions of their respective service water systems are being met.

Background:

Bulletin No. 81-03: The NRC staff has been studying the problems associated with service water cooling systems for a number of years. At Arkansas Nuclear One, Unit 2, on September 3, 1980, the licensee shut down the plant when the NRC Resident Inspector discovered that the service water flow rate through the

CONTACT: C. Vernon Hodge, NRR
492-1169

containment cooling units did not meet the technical specification requirement. The licensee determined the cause to be extensive flow blockage by Asiatic clams (Corbicula species, a non-native fresh water bivalve mollusk). Prompted by this event and after determining that it represented a generic problem of safety significance, the NRC issued Bulletin No. 81-03, "Flow Blockage of Cooling Water to Safety System Components by Corbicula sp. (Asiatic Clam) and Mytilus sp. (Mussel)."

The bulletin required licensees and applicants to assess macroscopic biological fouling (biofouling) problems at their respective facilities in accordance with specific actions. A careful assessment of responses to the bulletin indicated that existing and potential fouling problems are generally unique to each facility ("Closeout of IE Bulletin 81-03...", NUREG/CR-3054), but that surprisingly, more than half the 129 nuclear generating units active at that time were considered to have a high potential for biofouling. At that time, the activities of licensees and applicants for biofouling detection and control ranged widely and, in many instances, were judged inappropriate to ensure safety system reliability. Too few of the facilities with high potential for biofouling had adopted effective control programs.

Information Notice No. 81-21: After issuance of Bulletin No. 81-03, one event at San Onofre Unit 1 and two events at the Brunswick station indicated that conditions not explicitly discussed in the bulletin can occur and cause loss of direct access to the UHS. These conditions include

1. Flow blockage by debris from shellfish other than Asiatic clams and blue mussels.

2. Flow blockage in heat exchangers causing high pressure drops that can deform baffles and allow flow to bypass heat exchanger tubes.

3. A change in operating conditions, such as a change from power operation to a lengthy outage, that permits a buildup of biofouling organisms.

The NRC issued Information Notice No. 81-21 to describe these events and concerns.

Generic Issue 51: By March 1982, several reports of serious fouling events caused by mud, silt, corrosion products, or aquatic bivalve organisms in open-cycle service water systems had been received. These events led to plant shutdowns, reduced power operation for repairs and modifications, and degraded modes of operation. This situation led the NRC to establish Generic Issue 51, "Improving the Reliability of Open-Cycle Service Water Systems." To resolve this issue, the NRC initiated a research program to compare alternative surveillance and control programs to minimize the effects of fouling on plant safety. Initially, the program was restricted to a study of biofouling, but in 1987 the program was expanded to also address fouling by mud, silt, and corrosion products.

This research program has recently been completed and the results have been published in "Technical Findings Document for Generic Issue 51...," NUREG/CR-5210. The NRC has concluded that the issue will be resolved when licensees

and applicants implement either the recommended surveillance and control program described below (Enclosure 1) or its equivalent for the service water system at their respective facilities. Many licensees experiencing service water macroscopic biofouling problems at their plants have found that these techniques will effectively prevent recurrence of such problems. The examination of alternative corrective action programs is documented in "Value/Impact Analysis for Generic Issue 51...," NUREG/CR-5234.

Continuing Problems: Since the advent of Generic Issue 51, a considerable number of events with safety implications for the service water system have been reported. A number of these have been described in information notices, which are listed in "Information Notices Related to Fouling Problems in Service Water Systems" (Enclosure 3). Several events have been reported within the past 2 years: Oconee Licensee Event Report (LER) 50-269/87-04, Rancho Seco LER 50-312/87-36, Catawba LER 50-414/88-12, and Trojan LER 50-344/88-29. In the fall of 1988, the NRC conducted a special announced safety system functional inspection at the Surry station to assess the operational readiness of the service water and recirculation spray systems. A number of regulatory violations were identified (NRC Inspection Reports 50-280/88-32 and 50-281/88-32).

AEOD Case Study: In 1987, the Office for Analysis and Evaluation of Operational Data (AEOD) in the NRC initiated a systematic and comprehensive review and evaluation of service water system failures and degradations at light water reactors from 1980 to early 1987. The results of this AEOD case study are published in "Operating Experience Feedback Report - Service Water System Failures and Degradations," NUREG-1275, Volume 3 (Enclosure 4).

Of 980 operational events involving the service water system reported during this period, 276 were deemed to have potential generic safety significance. A majority (58 percent) of these events with generic significance involved system fouling. The fouling mechanisms included corrosion and erosion (27 percent), biofouling (10 percent), foreign material and debris intrusion (10 percent), sediment deposition (9 percent), and pipe coating failure and calcium carbonate deposition (1 percent).

The second most frequently observed cause of service water system degradations and failures is personnel and procedural errors (17 percent), followed by seismic deficiencies (10 percent), single failures and other design deficiencies (6 percent), flooding (4 percent), and significant equipment failures (4 percent).

During this period, 12 events involved a complete loss of service water system function. Several of the significant causes listed above for system degradation were also contributors to these 12 events involving system failure.

The study identified the following actions as potential NRC requirements.

1. Conduct, on a regular basis, performance testing of all heat exchangers, which are cooled by the service water system and which are needed to perform a safety function, to verify heat exchanger heat transfer capability.

2. Require licensees to verify that their service water systems are not vulnerable to a single failure of an active component.

3. Inspect, on a regular basis, important portions of the piping of the service water system for corrosion, erosion, and biofouling.

4. Reduce human errors in the operation, repair, and maintenance of the service water system.

Recommended Actions To Be Taken by Addressees:

On the basis of the discussion above, the NRC requests that licensees and applicants perform the following or equally effective actions to ensure that their service water systems are in compliance and will be maintained in compliance with 10 CFR Part 50, Appendix A, General Design Criteria 44, 45, and 46 and Appendix B, Section XI. If a licensee or applicant chooses a course of action different from the recommendations below, the licensee or applicant should document and retain in appropriate plant records a justification that the heat removal requirements of the service water system are satisfied by use of the alternative program.

Because the characteristics of the service water system may be unique to each facility, the service water system is defined as the system or systems that transfer heat from safety-related structures, systems, or components to the UHS. If an intermediate system is used between the safety-related items and the system rejecting heat to the UHS, it performs the function of a service water system and is thus included in the scope of this Generic Letter. A closed-cycle system is defined as a part of the service water system that is not subject to significant sources of contamination, one in which water chemistry is controlled, and one in which heat is not directly rejected to a heat sink. If all these conditions are not satisfied, the system is to be considered an open-cycle system in regard to the specific actions required below. (The scope of closed cooling water systems is discussed in the industrial standard "Operation and Maintenance of Nuclear Power Plants," ASME/ANSI OM-1987, Part 2.)

I. For open-cycle service water systems, implement and maintain an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling. A program acceptable to the NRC is described in "Recommended Program to Resolve Generic Issue 51" (Enclosure 1). It should be noted that Enclosure 1 is provided as guidance for an acceptable program. An equally effective program to preclude biofouling would also be acceptable. Initial activities should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter. All activities should be documented and all relevant documentation should be retained in appropriate plant records.

II. Conduct a test program to verify the heat transfer capability of all safety-related heat exchangers cooled by service water. The total test

program should consist of an initial test program and a periodic retest program. Both the initial test program and the periodic retest program should include heat exchangers connected to or cooled by one or more open-cycle systems as defined above. Operating experience and studies indicate that closed-cycle service water systems, such as component cooling water systems, have the potential for significant fouling as a consequence of aging-related in-leakage and erosion or corrosion. The need for testing of closed-cycle system heat exchangers has not been considered necessary because of the assumed high quality of existing chemistry control programs. If the adequacy of these chemistry control programs cannot be confirmed over the total operating history of the plant or if during the conduct of the total testing program any unexplained downward trend in heat exchanger performance is identified that cannot be remedied by maintenance of an open-cycle system, it may be necessary to selectively extend the test program and the routine inspection and maintenance program addressed in Action III, below, to the attached closed-cycle systems.

A program acceptable to the NRC for heat exchanger testing is described in "Program for Testing Heat Transfer Capability" (Enclosure 2). It should be noted that Enclosure 2 is provided as guidance for an acceptable program. An equally effective program to ensure satisfaction of the heat removal requirements of the service water system would also be acceptable.

Testing should be done with necessary and sufficient instrumentation, though the instrumentation need not be permanently installed. The relevant temperatures should be verified to be within design limits. If similar or equivalent tests have not been performed during the past year, the initial tests should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter.

As a part of the initial test program, a licensee or applicant may decide to take corrective action before testing. Tests should be performed for the heat exchangers after the corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance. In the periodic retest program, a licensee or applicant should determine after three tests the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests. Therefore, in the periodic retest program, to assist that determination, tests should be performed for the heat exchangers before any corrective actions are taken. As in the initial test program, tests should be repeated after any corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance.

An example of an alternative action that would be acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing for degraded performance of the heat exchanger. This alternative might apply to small heat exchangers, such as lube oil coolers or pump bearing coolers or readily serviceable heat exchangers located in low radiation areas of the facility.

In implementing the continuing program for periodic retesting of safety-related heat exchangers cooled by service water in open-cycle systems, the initial frequency of testing should be at least once each fuel cycle, but after three tests, licensees and applicants should determine the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests and meet the requirements of GDC 44, 45, and 46. The minimum final testing frequency should be once every 5 years. A summary of the program should be documented, including the schedule for tests, and all relevant documentation should be retained in appropriate plant records.

III. Ensure by establishing a routine inspection and maintenance program for open-cycle service water system piping and components that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of the safety-related systems supplied by service water. The maintenance program should have at least the following purposes:

A. To remove excessive accumulations of biofouling agents, corrosion products, and silt;

B. To repair defective protective coatings and corroded service water system piping and components that could adversely affect performance of their intended safety functions.

This program should be established before plant startup following the first refueling outage beginning 9 months after the date of this letter. A description of the program and the results of these maintenance inspections should be documented. All relevant documentation should be retained in appropriate plant records.

IV. Confirm that the service water system will perform its intended function in accordance with the licensing basis for the plant. Reconstitution of the design basis of the system is not intended. This confirmation should include a review of the ability to perform required safety functions in the event of failure of a single active component. To ensure that the as-built system is in accordance with the appropriate licensing basis documentation, this confirmation should include recent (within the past 2 years) system walkdown inspections. This confirmation should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter. Results should be documented and retained in appropriate plant records.

V. Confirm that maintenance practices, operating and emergency procedures, and training that involves the service water system are adequate to ensure that safety-related equipment cooled by the service water system will function as intended and that operators of this equipment will perform effectively. This confirmation should include recent (within the past 2 years) reviews of practices, procedures, and training modules. The intent of this action is to

reduce human errors in the operation, repair, and maintenance of the service water system. This confirmation should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter. Results should be documented and retained in appropriate plant records.

Reporting Requirements:

Pursuant to the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f), each licensee and applicant shall advise the NRC whether it has established programs to implement Recommendations I-V of this Generic Letter or that it has pursued an equally effective alternative course of action. Each addressee's response to this requirement for information shall be made to the NRC within 180 days of receipt of this Generic Letter. Licensees and applicants shall include schedules of plans for implementation of the various actions. The detailed documentation associated with this Generic Letter should be retained in appropriate plant records.

The response shall be submitted to the appropriate regional administrator under oath and affirmation under the provisions of Section 182a, Atomic Energy Act of 1954, as amended and 10 CFR 50.54(f). In addition, the original cover letter and a copy of any attachment shall be transmitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington DC 20555, for reproduction and distribution.

In addition to the 180-day response, each licensee and applicant shall confirm to the NRC that all the recommended actions or their justified alternatives have been implemented within 30 days of such implementation. This response need only be a single response to indicate that all initial tests or activities have been completed and that continuing programs have been established.

This request is covered by the Office of Management and Budget Clearance Number 3150-0011, which expires December 31, 1989. The estimated average burden is 1000 man-hours per addressee response, including assessing the actions to be taken, preparing the necessary plans, and preparing the 180-day response. This estimated average burden pertains only to these identified response-related matters and does not include the time for actual implementation of the recommended actions. Comments on the accuracy of this estimate and suggestions to reduce the burden may be directed to the Office of Management and Budget, Reports Management, Room 3208, New Executive Office Building, Washington, DC 20503 and to the U.S. Nuclear Regulatory Commission, Records and Reports Management Branch, Office of Information and Resources Management, Washington, DC 20555.

Although no specific request or requirement is intended, the following information would be helpful to the NRC in evaluating the cost of this Generic Letter:

1. Addressee time necessary to perform the requested confirmation and any needed follow-up actions.

2. Addressee time necessary to prepare the requested documentation.

If there are any questions regarding this letter, please contact the regional administrator of the appropriate NRC regional office or your project manager in this office.

Sincerely,

James G. Partlow
Associate Director for Projects
Office of Nuclear Reactor Regulation

Enclosures:
1. "Recommended Program to Resolve Generic Issue 51"
2. "Program for Testing Heat Transfer Capability"
3. "Information Notices Related to Fouling Problems in Service Water Systems"
4. "Operating Experience Feedback Report - Service Water System Failures and Degradations in Light Water Reactors," NUREG-1275, Volume 3
5. List of Most Recently Issued Generic Letters

Enclosure 1

RECOMMENDED PROGRAM TO RESOLVE GENERIC ISSUE 51

This enclosure describes a program acceptable to the NRC for meeting the objectives of the requested Action I in the proposed generic letter. Both Action I and this enclosure are based upon the recommendations described in "Technical Findings Document for Generic Issue 51: Improving the Reliability of Open-Cycle Service-Water Systems," NUREG/CR-5210, August 1988, and "Value/Impact Analysis for Generic Issue 51: Improving the Reliability of Open-Cycle Service-Water Systems," NUREG/CR-5234, February 1989. The NRC has concluded that Generic Issue 51 will be resolved when licensees and applicants implement either the recommended surveillance and control program addressed in this enclosure or an equally effective alternative course of action to satisfy the heat removal requirements of the service water system.

Water Source Type	Surveillance Techniques	Control Techniques
Marine or Estuarine (brackish) or Freshwater with clams	A	B and C
Freshwater without clams	A and D	B and C

A. The intake structure should be visually inspected, once per refueling cycle, for macroscopic biological fouling organisms (for example, blue mussels at marine plants, American oysters at estuarine plants, and Asiatic clams at freshwater plants), sediment, and corrosion. Inspections should be performed either by scuba divers or by dewatering the intake structure or by other comparable methods. Any fouling accumulations should be removed.

B. The service water system should be continuously (for example, during spawning) chlorinated (or equally effectively treated with another biocide) whenever the potential for a macroscopic biological fouling species exists (for example, blue mussels at marine plants, American oysters at estuarine plants, and Asiatic clams at freshwater plants). Chlorination or equally effective treatment is included for freshwater plants without clams because it can help prevent microbiologically influenced corrosion. However, the chlorination (or equally effective) treatment need not be as stringent for plants where the potential for macroscopic biological fouling species does not exist compared to those plants where it does. Precautions should be taken to obey Federal, State, and local environmental regulations regarding the use of biocides.

C. Redundant and infrequently used cooling loops should be flushed and flow tested periodically at the maximum design flow to ensure that they are not fouled or clogged. Other components in the service water system should be tested on a regular schedule to ensure that they are not fouled or

clogged. Service water cooling loops should be filled with chlorinated or equivalently treated water before layup. Systems that use raw service water as a source, such as some fire protection systems, should also be chlorinated or equally effectively treated before layup to help prevent microbiologically influenced corrosion. Precautions should be taken to obey Federal, State, and local environmental regulations regarding the use of biocides.

D. Samples of water and substrate should be collected annually to determine if Asiatic clams have populated the water source. Water and substrate sampling is only necessary at freshwater plants that have not previously detected the presence of Asiatic clams in their source water bodies. If Asiatic clams are detected, utilities may discontinue this sampling activity if desired, and the chlorination (or equally effective) treatment program should be modified to be in agreement with paragraph B, above.

Enclosure 2

PROGRAM FOR TESTING HEAT TRANSFER CAPABILITY

This enclosure describes a program acceptable to the NRC for meeting the objectives of the requested Action II in the proposed generic letter. Both Action II and this enclosure are based in part on "Operating Experience Feedback Report - Service Water System Failures and Degradations," NUREG-1275, Volume 3, November 1988 and "Technical Findings Document for Generic Issue 51: Improving the Reliability of Open Cycle Service Water Systems," NUREG/CR-5210, August 1988. This enclosure reflects continuing operational problems, inspection reports, and industry standards ("Operation and Maintenance of Nuclear Power Plants," ASME/ANSI OM-1987, Part 2.) The NRC requests licensees and applicants to implement either the steps addressed in this enclosure or an equally effective alternative course of action to satisfy the heat removal requirements of the service water system.

Both the initial test program and the periodic retest program should include all safety-related heat exchangers connected to or cooled by one or more open-cycle service water systems. A closed-cycle system is defined as a part of the service water system that is not subject to significant sources of contamination, one in which water chemistry is controlled, and one in which heat is not directly rejected to a heat sink. (The scope of closed cooling water systems is discussed in the industrial standard, "Operation and Maintenance of Nuclear Power Plants," ASME/ANSI OM-1987, Part 2.) If during the conduct of the total testing program any unexplained downward trend in heat exchanger performance is identified that cannot be remedied by maintenance of an open-cycle system, it may be necessary to selectively extend the test program to the attached closed-cycle system.

Testing should be done with necessary and sufficient instrumentation, though the instrumentation need not be permanently installed.

As a part of the initial test program, a licensee or applicant may decide to take corrective action before testing. Tests should be performed for the heat exchangers after the corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance. In the periodic retest program, a licensee or applicant should determine after three tests the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests. Therefore, in the periodic retest program, to assist that determination, tests should be performed for the heat exchangers before any corrective actions are taken. As in the initial test program, tests should be repeated after any corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance.

An example of an alternative action that would be acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing for degraded performance of the heat exchanger. This alternative might apply to small heat exchangers, such as lube oil coolers or pump bearing coolers or readily serviceable heat exchangers located in low radiation areas of the facility.

In implementing the continuing program for periodic retesting of safety-related heat exchangers cooled by service water in open-cycle systems, the initial frequency of testing should be at least once each fuel cycle, but after three tests, licensees and applicants should determine the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests and meet the requirements of GDC 44, 45, and 46. The minimum final testing frequency should be once every 5 years.

I. For all heat exchangers

Monitor and record cooling water flow and inlet and outlet temperatures for all affected heat exchangers during the modes of operation in which cooling water is flowing through the heat exchanger. For each measurement, verify that the cooling water temperatures and flows are within design limits for the conditions of the measurement. The test results from periodic testing should be trended to ensure that flow blockage or excessive fouling accumulation does not exist.

II. In addition to the considerations for all heat exchangers in Item I, for water-to-water heat exchangers

A. Perform functional testing with the heat exchanger operating, if practical, at its design heat removal rate to verify its capabilities. Temperature and flow compensation should be made in the calculations to adjust the results to the design conditions. Trend the results, as explained above, to monitor degradation. An example of this type of heat exchanger would be that used to cool a diesel generator. Engine jacket water flow and temperature and service water flow and temperature could be monitored and trended during the diesel generator surveillance testing.

B. If it is not practical to test the heat exchanger at the design heat removal rate, then trend test results for the heat exchanger efficiency or the overall heat transfer coefficient. Verify that heat removal would be adequate for the system operating with the most limiting combination of flow and temperature.

III. In addition to the considerations for all heat exchangers in Item I, for air-to-water heat exchangers

A. Perform efficiency testing (for example, in conjunction with surveillance testing) with the heat exchanger operating under the maximum heat load that can be obtained practically. Test results should be corrected for the off-design conditions. Design heat removal capacity should be verified. Results should be trended, as explained above, to identify any degraded equipment.

B. If it is not possible to test the heat exchanger to provide statistically significant results (for example, if error in the measurement exceeds the value of the parameter being measured), then

1. Trend test results for both the air and water flow rates in the heat exchanger.

2. Perform visual inspections, where possible, of both the air and water sides of the heat exchanger to ensure cleanliness of the heat exchanger.

IV. In addition to the considerations for all heat exchangers in Item I, for types of heat exchangers other than water-to-water or air-to-water heat exchangers (for example, penetration coolers, oil coolers, and motor coolers)

A. If plant conditions allow testing at design heat removal conditions, verify that the heat exchanger performs its intended functions. Trend the test results, as explained above, to monitor degradation.

B. If testing at design conditions is not possible, then provide for extrapolation of test data to design conditions. The heat exchanger efficiency or the overall heat transfer coefficient of the heat exchanger should be determined whenever possible. Where possible, provide for periodic visual inspection of the heat exchanger. Visual inspection of a heat exchanger that is an integral part of a larger component can be performed during the regularly scheduled disassembly of the larger component. For example, a motor cooler can be visually inspected when the motor disassembly and inspection are scheduled.

Enclosure 3

INFORMATION NOTICES RELATED TO FOULING PROBLEMS IN SERVICE WATER SYSTEMS

1. Information Notice No. 83-46: "Common-Mode Valve Failures Degrade Surry's Recirculation Spray Subsystem," July 11, 1983

2. Information Notice No. 85-24: "Failures of Protective Coatings in Pipes and Heat Exchangers," March 26, 1985

3. Information Notice No. 85-30: "Microbiologically Induced Corrosion of Containment Service Water System," April 19, 1985

4. Information Notice No. 86-96: "Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems," November 20, 1986

5. Information Notice No. 87-06: "Loss of Suction to Low Pressure Service Water System Pumps Resulting from Loss of Siphon," January 30, 1987

Enclosure 5

LIST OF RECENTLY ISSUED GENERIC LETTERS

Generic Letter No.	Subject	Date of Issuance	Issued To
89-13	GENERIC LETTER 89-13 SERVICE WATER SYSTEMS PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT	7/18/89	LICENSEES TO ALL POWER REACTORS BWRS, PWRS, AND VENDORS IN ADDITION TO GENERAL CODES APPLICABLE TO GENERIC LETTERS
89-12	GENERIC LETTER 89-12: OPERATOR LICENSING EXAMINATIONS	7/6/89	LICENSEES TO ALL POWER REACTORS BWRS, PWRS, AND VENDORS IN ADDITION TO GENERAL CODES APPLICABLE TO GENERIC LETTERS
89-11	GENERIC LETTER 89-11: RESOLUTION OF GENERIC ISSUE 101 "BOILING WATER REACTOR WATER LEVEL REDUNDANCY"	6/30/89	ALL BWR PLANTS & ALL LISTINGS APPLICABLE TO GENERIC LETTERS & VENDORS, ETC.
89-10	GENERIC LETTER 89-10: SAFETY-RELATED MOTOR-OPERATED VALVE TESTING AND SURVEILLANCE	6/28/89	LICENSEES TO ALL POWER REACTORS, BWRS, PWRS, AND VENDORS IN ADDITION TO GENERAL CODES APPLICABLE TO GENERIC LETTERS
89-09	ASME SECTION III COMPONENT REPLACEMENTS	5/8/89	ALL HOLDERS OF LIGHT WATER REACTOR OPERATING LICENSES
89-08	ISSUANCE OF GENERIC LETTER 89-08: EROSION/CORROSION - INDUCED PIPE WALL THINNING - 10 CFR §50.54(f)	5/2/89	LICENSEES TO ALL POWER REACTORS, BWRS, PWRS, AND VENDORS IN ADDITION TO GENERAL CODES APPLICABLE TO GENERIC LETTERS
89-07	GENERIC LETTER 89-07, POWER REACTOR SAFEGUARDS CONTINGENCY PLANNING FOR SURFACE VEHICLE BOMBS	4/28/89	LICENSEES TO ALL BWRS, PWRS, AND VENDORS IN ADDITION TO GENERAL CODES APPLICABLE TO GENERIC LETTERS

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

April 4, 1990

TO: ALL HOLDERS OF OPERATING LICENSES OR CONSTRUCTION PERMITS FOR NUCLEAR POWER PLANTS

SUBJECT: SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT (GENERIC LETTER 89-13, SUPPLEMENT 1)

On July 18, 1989, the U.S. Nuclear Regulatory Commission (NRC) issued Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." On October 23, 1989, the NRC announced in the Federal Register that it would hold four workshops on this generic letter. The NRC conducted these workshops in Philadelphia, Atlanta, Chicago, and Denver on November 28 and 30 and December 5 and 7, 1989, respectively. The NRC answered written questions submitted through appropriate project managers in the Office of Nuclear Reactor Regulation before the first workshop and questions submitted at each workshop. Transcripts of these meetings are available in the NRC Public Document Room, 2120 L Street NW, Washington, DC.

This supplement contains the questions and answers read into the transcripts during the workshops, except for the following changes. Questions received in the general, Action I, and Action II categories have been grouped according to topic. In addition, the NRC staff modified some answers after the workshops with the aim of furnishing additional guidance. Please contact the project manager if you have questions on this matter.

Sincerely,

James G. Partlow
Associate Director for Projects
Office of Nuclear Reactor Regulation

Enclosures:
1. Questions and Answers
2. List of Recently Issued NRC Generic Letters

Technical Contact: C. Vernon Hodge, NRR
(301) 492-1169

IDR-5
GL

9003300128 ZA

Enclosure 1

QUESTIONS AND ANSWERS

I. GENERAL

A. Reporting Requirements

1. If we are looking into several options to determine which one is the most beneficial, however, [if] we have not made a decision by the date that our response is due, would it be acceptable to explain this and confirm that whatever option is chosen will be completed on time? (Wisconsin Public Service)

Answer

Yes. The purpose of the 180-day response was to obtain the commitments, plans, and schedules of licensees and applicants to implement the recommended actions of the generic letter (GL) or their equally effective alternatives. The licensee's or applicant's decision-making process should be made a part of the plans and schedules and submitted to the NRC when the response is due. If other circumstances prevent such submittal, such as the regulatory requirements of the technical specifications or outside government agencies, the licensee or applicant should arrange any adjustments of the schedule with the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

2. What was the basis (experience) used to determine the schedule of completion for Items 2 and 4? Do these schedules consider utilities with more than one plant? (Northeast Utilities)

Answer

The basis for the schedule was an appearance of reasonableness. The schedules given apply to single units. Schedules are intended to be flexible and should be reported to the staff in the licensee's or applicant's response with justification if the recommended schedule in Generic Letter 89-13 is not used. The licensee or applicant should arrange any adjustments of the schedule with the appropriate NRR project manager.

3. If the CCWS [component cooling water system] is part of the scope for Items IV, V of the generic letter, would it be possible to modify the completion date commitments to fit this into our already existing SSFI [safety system functional inspection] schedule? (Wisconsin Public Service)

Answer

Yes. See the answer to Question I.A.1. Also, this request appears to be reasonable for good cause. The licensee or applicant should arrange any adjustments of the schedule with the appropriate NRR project manager.

4. Can we defer the Unit 2 required action dates so that they coincide with those of Unit 1 (i.e., October 1990 to April 1991 for Unit 2)? (Houston Lighting and Power)

Answer

Yes, with appropriate justification and arrangement with the appropriate project manager.

5. For Action Items 4 and 5 of the GL 89-13, HL&P [Houston Lighting and Power] plans to utilize the information gathered from a safety system functional inspection (SSFI) for the essential cooling water (ECW) and component cooling water (CCW) systems.

   The SSFI for the ECW system supports the GL 89-13 reporting requirements; however, the CCW SSFI is scheduled for 1990. Is it acceptable to separate the reporting for the ECW and CCW systems, that is, extend the CCW portion of GL 89-13? (Houston Lighting and Power)

   Answer

   Yes. See the answers to Questions I.A.1 and I.A.3.

6. The SSFI method currently being used to satisfy Recommended Actions IV and V is manhour intensive. Can program deficiencies identified in the open-loop system be applied horizontally to the closed-loop systems in lieu of an additional SSFI? (Houston Lighting and Power)

   Answer

   Yes. A licensee or applicant may extend identified deficiencies, based on other actions already taken (such as an SSFI) on the open-loop system, to the closed-loop system, provided the licensee or applicant confirms that existing configuration control programs have been applied to the closed-loop system.

B. Backfit

1. The actions proposed by GL 89-13 constitute new staff positions. To perform the testing and inspection requested by the GL, it may well be necessary for licensees to make significant plant modifications. For example, licensees will likely be forced to install new instrumentation in order to perform tests and to monitor test results. Furthermore, changes will be required of procedures. An additional requirement of a walkdown has been made. The proposed tests may be beyond the licensing basis of the plant. These requirements seem to fit the definition of a backfit under 10 CFR 50.109(a)(1). Therefore, why were the requirements in the GL promulgated under the provisions of Section 50.54(f)? (Nuclear Utility Backfitting and Reform Group [NUBARG])

   Answer

   The NRC concluded that it was not assured that licensees and applicants are in compliance with existing regulations, namely General Design Criteria 44, 45, and 46 of Appendix A of 10 CFR Part 50 and Appendix B of that part. The recommended actions in this generic letter do represent new staff positions and are considered a backfit in accordance with NRC procedures. This backfit is to bring facilities into compliance with existing requirements. The regulatory request for information under 10 CFR 50.54(f) represented by the generic letter is designed to gain this assurance.

2. Was a backfit analysis of the testing and inspection requirements performed? Will the staff make that analysis available to the public? In particular, did the staff's backfitting analysis, if any, justify the need for actions on closed systems? (NUBARG)

   Answer

   The staff performed an analysis for review by the NRC Committee to Review Generic Requirements (CRGR). Because the CRGR reviews all proposed bulletins and generic letters, among other proposed staff actions, this may properly be referred to as a regulatory analysis pursuant to 10 CFR 50.54(f). The CRGR analysis is available in the NRC public document room (Accession No. 8907180077).

   Indeed, the staff was not able to justify inclusion of closed systems in the recommended actions of the generic letter, as it had once proposed to do. Accordingly, the generic letter was issued without the requirement for reporting heat transfer capability of closed-cycle heat exchangers.

C. Inspections

1. What level of detail should be included in the descriptions of existing and proposed programs? (Philadelphia Electric)

Answer

The level of detail retained in plant records should be sufficient to demonstrate that the heat removal requirements of the service water system are satisfied. Each recommended action delineated in the generic letter or equivalent should be addressed in sufficient detail to demonstrate the licensee's evaluation of the action. It should be noted that this information should be available in appropriate plant records but need not be submitted to the NRC.

2. Generic Letter 89-13 provides the licensee with a great deal of leeway in defining their programs. This leeway is desirable and justifiable given the wide variation in conditions that may prevail. It is anticipated that the main mechanism for judging compliance with the generic letter will be NRC site inspections. During such inspections, what will be the basis for judging the acceptability of the program? What is being done to promote consistency in interpretations among regions? (Duke Power)

Answer

The engineering judgment of the inspector, based on the addressee's documentation for the program, will be relied upon to determine acceptability of the program. The purpose of the generic letter is for licensees and applicants to assure that the heat removal requirements for the service water system are satisfied. This is required by regulations, particularly General Design Criteria 44, 45, and 46 of Appendix A of 10 CFR Part 50 and Appendix B of that part.

The workshops constitute to date the NRC effort to promote consistency among the regions regarding Generic Letter 89-13. The NRC will issue the questions and answers submitted before and during the workshops as a supplement to Generic Letter 89-13 within the next two months. The traditional method of issuing a temporary instruction for inspection from headquarters to regional offices will not be used for this generic letter. At this time, only audits of implementation of Generic Letter 89-13 are planned rather than systematic inspections. If an event or problem related to the service water system occurs at a particular plant, that plant's actions in response to Generic Letter 89-13 will be reviewed to determine if inadequacies in the implementation of the Generic Letter contributed to the event or problem. The supplement to Generic Letter 89-13 will also reference the transcripts for these workshops, which will be placed in the NRC public document room. Authors of the generic letter will be available by telephone to licensees, applicants, and inspectors to address questions on implementation of the Generic Letter.

3. Many of your responses this morning (Workshop II in Atlanta on November 30, 1989) fall back to the standard NRC position that the licensee should provide adequate assurance that they have a program or actions in place to satisfy the generic letter concerns. This position could create a problem later when the inspector shows up to review our program. What kind of guidance will the NRR and RES [Office of Nuclear Regulatory Research] staff be providing to the inspector? If you don't provide specific instruction in something like a TI [temporary instruction], the acceptability of a given program will be left to the opinion of an individual inspector. When will this type of guidance be available? (Florida Power)

   Answer

   Both the kind of guidance and the schedule are discussed in the answer to the previous question, C.2.

4. When does the NRC envision inspections to begin on this letter? (Florida Power)

   Answer

   At this time, only audits of implementation of Generic Letter 89-13 are planned rather than systematic inspections. The schedules for such audits have not been determined at this time.

D. Miscellaneous

1. Similar regional meetings regarding Generic Letter 89-04 were conducted in the June 1989 time frame. To date, the minutes from these meetings have not been received. When can we expect the minutes from the Generic Letter 89-13 meetings? (Duke Power)

Answer

Concerning Generic Letter 89-04, the minutes were issued by letter dated October 25, 1989, signed by James Partlow, Associate Director for Projects, Office of Nuclear Reactor Regulation. The minutes are being distributed to all licensees and applicants, meeting attendees, NRR project managers, and the NRC public document room.

Concerning Generic Letter 89-13, see the answer to Question I.C.2. To repeat, the NRC will issue the questions and answers submitted before and during the workshops as a supplement to Generic Letter 89-13 within the next two months. The supplement to Generic Letter 89-13 will also reference the transcripts for these workshops, which will be placed in the NRC public document room.

2. Do Recommended Actions IV and V apply to closed cooling systems? (Kansas Gas and Electric)

Answer

Yes. The generic letter defines service water systems as including both open-cycle portions and intermediate closed-cycle loops that function to remove heat from safety-related structures, systems, or components to the ultimate heat sink. Recommended Actions I, II, and III specifically apply to open-cycle portions of the service water system. Recommended Action II can be extended to the closed-cycle portions as conditions warrant. Whether a cooling loop is open or closed is not specified for Actions IV and V.

II. ACTION I - BIOFOULING

A. Terms

1. What is the definition of layup? (Philadelphia Electric)

Answer

Layup is the treatment of a system that is isolated or in a standby condition under stagnant flow conditions to prevent corrosion. Refer to "Plant Layup and Equipment Preservation Sourcebook," EPRI NP-5106 (March 1987). Those service water cooling loops normally operated with water in the system, even in a standby condition, should contain chlorinated or equivalently treated water rather than untreated water.

2. What constitutes an infrequently used component? (Philadelphia Electric)

Answer

Paragraph C in Enclosure 1 in the generic letter states that redundant and infrequently used cooling loops should be flushed and flow tested periodically at the maximum design flow to ensure that they are not fouled or clogged. This recommended action refers to emergency core cooling system loops or other safety-related cooling loops that are normally in the standby condition. The next sentence states that other components in the service water system should be tested on a regular schedule to ensure that they are not fouled or clogged. This recommended action refers to pumps, pipes, valves, strainers, or other components even in loops in which water is normally flowing. Often inadequate flow may exist in these loops and not be detected without such testing.

Consider a system in which water is normally flowing that has parallel branches in which the states of the components in the branches are not often changed. For example, branch throttle valves initially set before the plant began operation may not be controlled by procedure. Subsequent changes in the throttle valve positions for various reasons or clogging of them or other components in the branches would upset the initial system flow balance without detection.

3. Redundant and infrequently used cooling loops: (Unidentified)

   a. Define infrequently used.

   Answer

   The wording "infrequently used cooling loops" is intended to apply to those normally in a standby mode under stagnant flow conditions. The Generic Letter 89-13 program should address means for ensuring that fouling does not occur under such conditions.

   b. If performance testing is done on all heat exchangers periodically, will this satisfy the intent of the recommendation?

Answer

Yes. Periodic performance monitoring of all safety-related heat exchangers is acceptable, provided it ensures heat transfer capability, not merely flow or pressure drop.

4. Recommendation I of Generic Letter 89-13 states that "initial activities should be completed before plant startup following the first refueling outage beginning nine months or more after the date of this letter." What is the intent of the phrase, "initial activities"? Does it mean:

The first "round" of activities (inspections, flushes, biocide treatment, etc.) has been completed; or,

The mechanisms have been put in place which will culminate in the implementation of the program (biocide discharge permits submitted, procedures written and approved)? (Duke Power)

Answer

Both these possibilities could be included in the intent of the phrase. For those activities involving an outside governmental agency, the licensee or applicant should arrange a needed adjustment in the schedule with the appropriate NRR project manager. For those activities involving procedural changes or new procedures, "initial activities" refers to those inspections or other activities by which the need for procedural changes or new procedures is identified.

B. Inspection of Intake Structure

1. When determining whether a plant has clams in its source water, does consideration need to be given to the presence of clams in the plant vicinity (local environment) or solely in the water body (source of cooling water)? (Philadelphia Electric)

Answer

The purpose of this recommended action is to enable a licensee or applicant to know if the service water system might be subject to biofouling. All potential sources of water for the service water system should be examined annually for the presence of biofouling species. If no waters in the local environment of a plant can get inside piping and components to cause biofouling degradation of the heat transfer function of the service water system, then such waters do not need to be sampled.

2. Enclosure 1 to Generic Letter 89-13 recommends varying requirements for service water systems based on intake structure configuration and location. In a service water system in which the suction point of the service water pumps is in the collecting basin for the ultimate heat sink (cooling tower) would the basin be considered the intake structure or would the source of basin makeup water be considered the intake structure? (Mississippi Power and Light)

Answer

Each licensee or applicant should define the scope of the intake structure. The NRC considers that an intake structure would contain all the waters eventually used in the system. See the answer to Question II.B.1.

3. Does the visual inspection of the intake structure apply to the intake piping as well? If so, will NRC give guidance as to replacement criteria of piping? If not, is [American National Standards Institute Standard] B31.1 for wall thinning the appropriate criteria? (Wisconsin Public Service)

Answer

Visual inspection of the intake structure may apply to the intake piping. The minimum wall thickness is defined by the code of record that was used to design the piping system. Before 1971, ANSI B31.1 was applicable. Since 1971, ASME Code Section 3 applies to piping design and fabrication.

4. When stating we should be aware of other plants (refer to Philadelphia workshop transcript, p. 21), facilities, etc., that use the same service water source (e.g., river) and their biofouling problems, how far does that extend? Within 5 miles? 50 miles? Please clarify. (Unidentified)

Answer

The NRC cannot place a quantitative range on biofouling awareness. Conditions at each site would determine an appropriate program or how far away to monitor for biofouling. The licensee or applicant should use the best available site-specific information and establish an appropriate monitoring program.

5. Refer to Action Item I in Gen. Ltr 89-13. If the current sampling program, which was initiated to detect Asiatic clams, has not found any mollusk infestation do the sampling methods need to be modified to detect Zebra mussels? (Niagara Mohawk Power)

Answer

The recommended sampling methods in Recommended Action I are intended to be general enough to enable licensees and applicants to become aware of macrobiofouling agents early enough to prevent the associated fouling problem from adversely affecting the safety-related function of the service water system. See Information Notice 89-76, "Biofouling Agent: Zebra Mussel."

6. Inspection of intake structure each refuel cycle. Could inspection of other intake structures (fossil units) on the same body of water that have been in place and in service for up to 40 years be used to justify either to extend the frequency of inspection or maybe no inspection at all? (Unidentified)

Answer

The inspection of the intake structure should not be restricted to potential macroinvertebrate fouling. If the program in place at the fossil unit mentioned has been shown to be effective to date for detecting of fouling, including biofouling, mud, and silt, then it may be sufficient for future monitoring. However, the licensee or applicant should be aware of and should consider possible rapid changes in environmental conditions and ensure that its program includes the best available site-specific information.

7. If it can be shown that the introduction of mollusks into the service water system is not plausible based on service water system design and makeup water system design, can the requirements of Generic Letter 89-13 concerning both inspection for <u>and</u> control of mollusks be waived? (Mississippi Power and Light)

Answer

The purpose of the generic letter is for licensees and applicants to assure that the heat removal requirements for the service water system are satisfied. If this can be done by the proposed program, then it is acceptable.

8. If yearly inspection of a plant's service water intake structure shows no indication of Asiatic clams, and testing results indicate that corrosion is not microbiologically influenced, is it acceptable to continue with the annual inspections for clams and perform maintenance and testing as required in Actions II and III of GL 89-13, in lieu of a chlorination injection program? (Commonwealth Edison)

   Answer

   This appears to be reasonable for good cause shown. See the answers to the previous two questions.

9. Larva sampling is difficult to do. We already have a sampling commitment, but we don't want to do this and can justify not doing it. (Kansas Gas and Electric)

   Answer

   An equally effective course of action with justification is acceptable. However, the earlier that a licensee or applicant can identify the presence of a biofouling species in a source body of water for the service water system, the better chance it will have to control the situation and prevent a potential safety problem.

10. Does the generic letter imply that biofouling monitoring methods are required? Are sidestream or inline monitoring methods necessary? Does the NRC have a preference concerning the methods of visual, UT [ultrasonic testing], radiography, or electrochemical (Corrator) probes to monitor for biofouling? (South Carolina Electric and Gas)

    Answer

    Biofouling monitoring of the source water would generally be necessary. Licensees and applicants may use, however, equally effective programs for Recommended Action I. Sidestream or inline monitoring is effective and could be used for this purpose. The NRC has no preference concerning methods for biofouling monitoring or nondestructive service water system examination provided the selected method is effective.

11. For NTOL [near-term operating license] plants, when does GL 89-13 have to be implemented? (Unidentified)

    Answer

    As stated in Generic Letter 89-13, both licensees and applicants should observe the same schedule. The licensee or applicant should arrange any justified adjustments of the schedule with the appropriate NRR project manager.

12. On Item C, Enclosure 1, since macroscopic biological fouling and MIC [microbiologically influenced corrosion] have not been problems at CNS [Cooper Nuclear Station], does that exempt us from the recommendation for chlorinating systems using raw water before layup? (Nebraska Public Power District)

Answer

Yes, if appropriate justification is provided.

13. Is periodic maintenance adequate to address layup without chlorination? (Nebraska Public Power District)

Answer

Yes, if appropriate justification is provided.

14. On Item D, Enclosure 1, in lieu of taking annual water samples to determine if Asiatic clams have populated the water source, could we perform annual visual inspections of sample heat exchangers cooled by river water? (Nebraska Public Power District)

Answer

The purpose of sampling the water source itself was to ensure that means of potential fouling were identified early. However, if the best available site-specific information does not indicate a means of biofouling, then visual examination of a sample of service water system heat exchangers may be sufficient, with proper justification, to detect fouling.

C. Biocide Guidance

1. Enclosure 1 to Generic Letter 89-13 describes an acceptable program, to the NRC, to implement Recommendation No. I of the generic letter. This program includes biocide treatment regardless of whether the plant is susceptible to macroscopic biological fouling or not. Will a program that does not include biocide treatment be acceptable to the NRC? (Duke Power)

Answer

Yes, if good cause is shown. Note the guidance in Paragraph B of Enclosure 1 to Generic Letter 89-13. Chlorination or equally effective treatment is included for freshwater plants without clams because it can help prevent microbiologically influenced corrosion.

2. With regards to Enclosure 1 of the generic letter; (Wisconsin Public Service)

a. Will NRC give guidance on use of biocides other than chlorine?

Answer

No. The NRC is interested in the effective heat transfer of the systems. It is not in a position to consult on the various biocide treatments. Refer to "Plant Layup and Equipment Preservation Sourcebook," EPRI NP-5106 (March 1987).

b. Do we need to continuously chlorinate, if under our inspection program, we find no evidence of macroscopic fouling? Do WPDES [sic; National Pollutant Discharge Elimination System] discharge limits take precedence to this?

Answer

No. The program described in Enclosure 1 represents an acceptable program for implementing Recommended Action I. A licensee or applicant can choose to pursue an equally effective alternative course of action if justified. Precautions should be taken to obey Federal, State, and local environmental regulations regarding the use of biocides. This includes the National Pollutant Discharge Elimination System (NPDES) discharge limits administered by the U.S. Environmental Protection Agency, which were referenced in the question.

c. Is demineralized water acceptable for use in wet layup of stagnant SW [service water] piping?

Answer

This question must be decided by the licensee or applicant. The result should be that the heat removal requirements for the service water system are satisfied. To accomplish this, the NRC recommends that such piping be flushed and flow tested periodically to ensure that clogging is absent and that chlorinated or equivalently treated water will be used to fill service water loops before layup to help prevent MIC. We note also that industry recommends treatment of service water systems during outages to prevent microbes. See EPRI NP-5106.

3. Some State regulations do not permit the use of biocides above the minimum detectable level, yet Enclosure 1 to the GL appears to require biocides while cautioning plants not to violate State and local regulations. Since it is not possible in some jurisdictions to use any biocides without violating State and local regulations, what alternatives to biocides are acceptable to the staff? (Nuclear Utility Backfit Action Reform Group [NUBARG])

Answer

An alternative course of action is acceptable if the heat removal requirements for the service water system are satisfied. Biocides can be deactivated before discharge. The treated biocides must meet NPDES discharge limits. At least one utility (Trojan) is deactivating the biocides before discharge. See the answers to the previous two questions.

D. Fire Protection Systems

1. To what extent should fire protection systems be addressed in response to the generic letter? (Philadelphia Electric)

Answer

The generic letter is not designed to focus on fire protection systems, which are not safety-related, but to incidentally include them if they use untreated water that could be subject to the service water system problems described in the generic letter.

2. We use well water (raw water) as a source to the fresh water/fire protection storage tanks. Do we need to chlorinate these tanks or do we need to conduct full-flow surveillance tests on all fire protection piping runs? We presently only surveil the fire pumps for flow, not the piping runs. We do not presently chlorinate these tanks. The SW system per se is not used to fill these tanks; separate well pumps are used. (Public Service Electric and Gas)

Answer

The recommended program described in Enclosure 1 of the generic letter was developed under a government-sponsored research program. If a licensee or applicant chooses an alternative course of action from that recommended in Enclosure 1, it should assess the potentials for macroscopic biofouling and microbiologically influenced corrosion (MIC) and justify that the alternative course of action will result in satisfaction of the heat removal requirements for the service water system.

Paragraph B of Enclosure 1 of the generic letter recommends chlorination whenever the potential for a macroscopic biological fouling species exists. Such a potential may not exist for these wells, but the potential for MIC should also be considered.

Paragraph C of Enclosure 1 of the generic letter recommends periodic flow testing of infrequently used loops at the maximum design flow to ensure that they are not fouled or clogged. If the fire protection piping runs are subject to biofouling but the water is not treated to protect against biofouling, then full-flow testing of the runs may be appropriate to ensure that the potential for clogging is minimal. This paragraph also recommends chlorination to help prevent MIC.

3. Do Generic Letter 89-13 requirements apply to the fire protection systems which are not fed by either the service water system or the service water Intake? (South Carolina Electric and Gas)

   Answer

   The generic letter is not designed to focus on fire protection systems, but to incidentally include them if they use untreated water that could be subject to the service water system problems described in the generic letter.

4. What is the basis for requiring treatment of fire protection systems that use raw service water as a source (Enclosure 1, Section C)? (NUBARG)

   Answer

   See the answers to the previous two questions.

5. For a fire protection system supplied by raw water which meets flow requirements and does not provide safety-related cooling, are any actions required? (Iowa Electric Light and Power)

   Answer

   No. See the answer to Question II.D.1.

III. ACTION II - HEAT TRANSFER TESTING

A. Testing Method

1. Should the proposed heat exchanger heat transfer testing method be provided for prior NRC review and approval? (Philadelphia Electric)

   Answer

   No.

2. Has the NRC reviewed the EPRI SWWG [Electric Power Research Institute Service Water Working Group] document prepared by Duke Power and Toledo Edison describing several methods of heat transfer testing? If so, is the temperature effectiveness method acceptable? Which methods are acceptable? (Philadelphia Electric)

   Answer

   The staff has not formally reviewed this document but has received a draft copy. A method of heat transfer testing is acceptable for purposes of satisfying the generic letter if it can assure that the heat removal requirements for the service water system are satisfied.

3. If the pressure drop across a heat exchanger at design flow is less than or equal to the manufacturer's specification, is heat transfer testing required, provided the baffles have been inspected to ensure that the flow is not bypassing the coils? (Philadelphia Electric)

   Answer

   The objective is not to satisfy the manufacturer's specification for flow in a heat exchanger so much as it is to ensure that the heat removal requirements for the service water system are satisfied. If the latter assurance can be achieved by showing design flow to be necessary and sufficient, then heat transfer testing would be superfluous.

4. Page 5, paragraph 3. What is meant by "The relevant temperatures should be verified to be within the design limits?" Does this imply testing should be conducted with the design-basis heat load? Is it acceptable to conduct testing for all heat exchangers at off normal conditions, provided accurate and relevant data can be acquired, and analytical methods used to determine the heat transfer capacity at design conditions? (Portland General Electric)

   Answer

   Enclosure 2 of the generic letter discusses in detail verifying various parameters to be within design limits. Testing with design-basis heat loads is recommended ideally. If testing can be done under design conditions, it should be done under those conditions. Realizing this may not be practicable in nonaccident circumstances, the next best step is to

conduct tests under off-design conditions and analytically correct the results to the design conditions. Such a procedure is acceptable if it is necessary but not if testing under design conditions is practicable.

5. For heat exchangers that cannot be tested at the design heat removal rate, what is the NRC-recommended method to extrapolate the test data to design conditions? Does the NRC have any additional recommendations for extrapolating test data taken at very low loads (less than 10% design load) to design conditions? (Southern California Edison)

Answer

The staff does not have a recommended method of extrapolation. However, the EPRI service water system working group has been developing such guidance as have some licensees such as Duke Power. These may be places to start when developing appropriate testing programs.

6. Recommended Action II requires that "the relevant temperatures should be verified to be within design limits." Also, Enclosure 2, Item II.A states, "Perform functional testing with the heat exchanger operating, if practical, at its design heat removal rate to verify its capabilities. Temperature and flow compensation should be made in the calculations to adjust the results to the design conditions."

It is not practical to test the heat exchangers at design heat removal rates. Also, we are unable to find a method which has the requisite level of precision to adjust the test results to design conditions.

Please discuss an acceptable method to adjust the test results to the design conditions. Also provide the scientific bases, or a reference, for the proposed method.

Also, the heat removal test cannot be performed on the containment spray heat exchangers because there is no heat source. The only test that can be performed is a pressure drop test. Is this acceptable? If not, what is recommended? (Indiana and Michigan Power)

Answer

As mentioned previously, the NRC does not have a recommended test method. See the answer to the previous question. With regard to the testing of containment spray heat exchangers, as of all safety-related heat exchangers, a pressure drop test alone is not sufficient to satisfy the indicated heat transfer capability concerns. If it is not practicable to test a heat exchanger, then the licensee or applicant may propose a program of periodic inspection, maintenance, and cleaning as an alternative. We are aware, however, of one licensee who was able to test the containment spray heat exchanger by heating the refueling water storage tank water approximately 10°F and then performing temperature monitoring tests as well as pressure drop tests.

7. To what degree should a utility endeavor to monitor real-time corrosion rates of the service water system? Is trending of heat exchanger performance and visual inspections sufficient documentation of the component's internal condition? (South Carolina Electric and Gas)

Answer

It is not necessary to determine numerical real-time corrosion rates in the service water system. The licensee's or applicant's monitoring program should be sufficient to identify degradation and to take the necessary corrective action before system performance is unacceptably affected. Trending of data is a recommended approach to monitoring system performance.

8. Is the NRC staff stating that a technical evaluation of a heat exchanger's capability to perform its design safety function cannot be used in lieu of initial testing? Therefore, all heat exchangers must be tested and even maintenance/cleaning cannot be used in lieu of initial testing because it would require a technical evaluation to determine maintenance/cleaning frequency. Also, when considering several identical heat exchangers in one loop, do all the heat exchangers require testing or maintenance/cleaning? (Philadelphia Electric)

Answer

No, the initial heat exchanger "test" program may consist of both performance testing of some heat exchangers and maintenance and cleaning of others. The initial test program was intended to ensure that the licensee or applicant has established a baseline for all safety-related heat exchangers served by the service water system and, therefore, is confident that they can perform their heat removal function. As further clarification, if there are several identical heat exchangers in one service water loop, a licensee or applicant may perform testing or develop a maintenance and cleaning program for these heat exchangers based on the most limiting one as part of its initial "test" program. Justification for the basis of comparable service conditions should be included in the evaluation when all identical heat exchangers are not tested.

9. Refer to Action Item II of Gen. Ltr 89-13. Can the test program include data taken during routine operating intervals, with minimum load on heat exchangers, and extrapolated to substantiate adequate HX [heat exchanger] performance? Or when does the NRC consider it impractical to test a HX at the design heat removal rate? (Niagara Mohawk Power)

Answer

Yes, if testing under design conditions is not practicable. See the answers to Questions III.A.4, III.A.5, and III.A.6 above. The licensee or applicant should determine whether such testing is practicable. See the answer to Question III.A.14.

10. In Enclosure 2 of the generic letter, a statement is made that testing should be done with necessary and sufficient instrumentation. Flow measurement is one of the two key parameters when measuring heat exchanger performance. It is also the most difficult since most plants never provided means to measure individual flow rates to service water users. In general, orifice plates, venturi tubes, pitot tubes and flow nozzles are the only recognized traceable type of flow measuring devices, all of which require intrusive elements. To be able to utilize such devices would require plant system modifications at great expense to the utility and its customers. A less expensive alternative to this would be to use non-intrusive, non-traceable devices such as transit-time ultrasonic flow meters which with current technology give very reliable results. Trending of data taken with such devices would appear to be equally effective for detecting degradation in cooling water systems. Would the NRC recognize the value and benefit of using such devices and accept programs which utilize them? (Detroit Edison)

    Answer

    Yes.

11. Thermographic cameras could potentially be used to scan the tubes on air to water heat exchangers to see temperature profiles of the tubes and detect tube blockage or sediment in the tubes. Will the NRC accept such qualitative checks rather than quantitative measurements to prove that a heat exchanger is not fouled? (Detroit Edison)

    Answer

    Yes. However, additional means should be included in the program to ensure adequate heat transfer.

12. If off-the-shelf software is reviewed for technical adequacy and subsequently utilized to perform heat exchanger performance calculations, will it be acceptable to the NRC? (Detroit Edison)

    Answer

    Yes.

13. If a heat exchanger performance test reveals that a heat exchanger is in a degraded condition, the first obvious question will be as to what the impact of the degraded condition is on system operability. Will a heat exchanger performance program be considered the same as the plant's surveillance program with the same ramifications for questioning plant/system operability? If so, is the NRC considering asking the licensees to include limiting condition for operation statements in their technical specifications? (Detroit Edison)

Answer

If a heat exchanger's heat transfer capability is shown to be degraded below levels needed for performance of its safety-related function, it is considered inoperable. The staff does not intend that elements of these programs be included in plant technical specifications.

14. Restate what you would consider acceptable as "impractical conditions for testing." What are "acceptable alternatives," especially for utilities not privy to EPRI information? (Portland General Electric)

Answer

An impractical condition would be a situation where flow or the means of applying a heat load cannot be achieved because of system configuration. An acceptable alternative is a periodic inspection or maintenance program for such heat exchangers. Impracticality itself is not a sufficient reason for excluding any heat exchanger from some verification of performance.

15. What if performable HX testing conditions (off design) cannot be used to demonstrate acceptable heat transfer (i.e., low delta T combined with instrument accuracies)? Is maintenance inspection our only alternative? (Portland General Electric)

Answer

If reasonable results cannot be obtained from performance testing, then inspection or maintenance is an appropriate alternative. A licensee may, however, be able to justify another acceptable alternative.

16. If the utility performs a baseline test that exceeds the design requirements but is below the mfg [manufacturer's] rating for this component HX, does the NRC consider this as a concern in that "design margin" has been lowered? (Arkansas Power and Light)

Answer

No. The staff's concern is not that a licensee or applicant maintain the initially specified design margin. If the licensee or applicant chooses to operate with a reduced margin, this is acceptable provided the safety-related heat removal requirements are satisfied.

B. Maintenance of Heat Exchangers

1. To what extent can routine maintenance/cleaning of heat exchangers replace testing? (Philadelphia Electric)

Answer

A licensee or applicant should determine the appropriate frequency of testing or maintenance activities to ensure that the heat removal requirements for the service water system are satisfied. For a given heat exchanger, a licensee or applicant may elect to clean, replace, repair, or otherwise maintain it initially before beginning a routine testing program. If the licensee or applicant elects to not implement a routine testing program for the heat exchanger, then a routine maintenance program may be necessary to provide the sought assurance. In the absence of a routine test program, no basis may be available for detecting potential degradation of heat transfer performance. In the absence of such a basis, the frequency of maintenance may have to be a maximum value to provide the sought assurance.

2. Page 5, paragraph 4. If the maintenance period is known why can't a test be performed before maintenance to establish a data point for the required testing or maintenance? If the overall maintenance period has been 3 or more fuel cycles could this be used to establish the test frequency? Is it necessary to retest a heat exchanger after maintenance if the work performed was a restoration only (i.e., cleaning not tube plugging) and testing had previously been conducted with clean heat transfer surfaces? (Portland General Electric)

Answer

All these steps are acceptable alternatives to the program outlined in Enclosure 2 in the generic letter. The justifications that these alternative procedures ensure that the heat removal requirements for the service water system are satisfied should be documented and retained in appropriate plant records.

3. Recommended Action II paragraph 5 states that frequent regular maintenance is an acceptable alternative to testing. What is meant by "frequent regular maintenance"? Does this mean more frequently than if testing were performed? This paragraph further states that this alternative might apply to small heat exchangers, . . . located in low radiation areas. . . . Would low radiation areas be defined by ALARA [as low as is reasonably achievable] practices or less than 100 mr/hr? (Unidentified)

Answer

The licensee or applicant is to establish the frequency of periodic testing or regular maintenance once sufficient data have been collected. The frequency should ensure that unacceptable degradation does not occur between testing or maintenance cycles. Low radiation areas as intended in Generic Letter 89-13 are included in the licensee's ALARA program so that

radiation levels will not preclude personnel access for maintenance and cleaning of heat exchangers.

4. GL 89-13 seems to imply that periodic maintenance (i.e., cleaning) of small accessible heat exchangers is acceptable in lieu of performance testing. If so, is a refueling maintenance frequency acceptable? (Northeast Utilities)

Answer

Yes. This is an acceptable initial frequency and may be acceptable in the long-term with justification based on data from a minimum of three refueling outages.

5. If maintenance is performed in lieu of testing for degraded performance of the heat exchanger, how extensive does the maintenance have to be? That is, does maintenance have to be performed on both sides of the HX or just on the service water side? (Niagara Mohawk Power)

Answer

Maintenance should be extensive enough to assure the heat removal requirements of the service water system are satisfied. See the answers to Questions III.B.1 and III.F.1.

6. Would a program involving inspection and maintenance activities in lieu of a performance test program be an acceptable program for all heat exchangers and components? (Nuclear Utility Backfit Action Reform Group [NUBARG])

Answer

Yes, if justification is provided.

7. Clarification of Item IV. B., Enclosure 2, on periodic visual inspection of small heat exchangers such as seal coolers. Are they included in the class to be inspected when the pump is inspected? (Nebraska Public Power District)

Answer

If the seal coolers in question are integral parts of larger components, such as pumps, then the coolers may be inspected visually during the regularly scheduled disassembly of the larger component. If not, then the seal coolers should be treated separately. Once it has been established that a small heat exchanger such as a seal cooler is performing satisfactorily, the licensee or applicant may choose to justify an extended program of periodic inspection (e.g., up to 5 years) on the basis of existing operating conditions, such as the cooling of loops not subject to fouling mechanisms.

8. ANO [Arkansas Nuclear One] is scheduled to chemically clean the entire SW system in the fall of 1990. Does this constitute an acceptable method to restore thermal performance in lieu of performance testing for the first outage? (Arkansas Power and Light)

Answer

The licensee or applicant should justify such an approach to satisfy this part of the generic letter. Since chemical cleaning is a corrective action, some followup verification such as visual examination or limited performance testing may be appropriate.

C. Number of Heat Exchangers To Be Tested

1. Is it acceptable to determine the most restrictive heat exchangers in each group for testing in lieu of testing every heat exchanger? (Philadelphia Electric)

Answer

The purpose of the generic letter is for licensees and applicants to assure that the heat removal requirements for the service water system are satisfied. If this can be done by the proposed program, then it is acceptable.

2. How much detail does the NRC expect for the response to Action II? Would the proposed test/maintenance/inspection method for each heat exchanger be necessary? (Public Service Electric and Gas)

Answer

Specific details of the licensee's or applicant's program in response to Action II should be developed and retained as part of plant records. Those heat exchangers not being included in programs under Action II should be identified and the basis given for their exclusion. Grouping of heat exchangers into categories based on the approach to be used would be acceptable.

3. Enclosure 2, page 2. The term "all heat exchangers" is used. Does this imply every heat exchanger of a given design must be tested or where more than one identical heat exchanger is used can one representative unit be selected? (Portland General Electric)

Answer

Recommended Action II calls for the testing of the heat transfer capability of all safety-related heat exchangers cooled by service water. The service water system is defined as the system or systems that transfer heat from safety-related structures, systems, or components to the ultimate heat sink. Each heat exchanger, regardless of redundancy, should be tested or maintained initially to establish that the heat removal requirements for the service water system are satisfied. Existence of identical conditions then can be used to determine the best test or maintenance frequencies to ensure that the heat removal requirements for the service water system are satisfied.

4. We would like to limit heat exchanger performance testing to one unit since the two units are identical. Is this an acceptable approach? (Houston Lighting and Power)

Answer

Not totally. See the answer to the previous question.

5. Is it acceptable to eliminate heat exchangers from the testing requirement of Action II if they are in parallel and/or in series with other heat exchangers which are tested and operated under similar service conditions (e.g., velocity, temperature, process fluid) (Ref. EPRI Heat Exchanger Performance Monitoring Guidelines for Service Water Systems)? (Commonwealth Edison)

Answer

Not totally. See the answer to Question III.C.3.

D. Frequency of Testing or Maintenance

1. Recommendation No. III [sic] does not specify a frequency for heat exchanger inspections. Is it the NRC's intent that the utility establish the frequency of these inspections? (GPU Nuclear)

Answer

Yes. Recommended Action II indicates limits. Initially, tests should be conducted at least once every fuel cycle. More frequent testing may be necessary to enable a conclusion that the heat removal requirements for the service water system are satisfied. After about three tests, a licensee or applicant may be in a position to set a different testing frequency. However, the finally determined testing frequency should not be less than once every 5 years.

2. Page 6, paragraph 1. Why were three tests chosen? Could a different number, more or less, be appropriate? (Portland General Electric)

Answer

The number three is the minimum number needed to establish a trend. A larger number would be appropriate, but a smaller number is insufficient.

3. Page 5, paragraph 5. What is meant by frequent regular maintenance? Can frequency be determined in a similar method as test frequency? (Portland General Electric)

Answer

Frequent regular maintenance is an acceptable alternative to Recommended Action II, which calls for heat exchanger performance testing. For small heat exchangers such as lube oil coolers, testing might be excessively burdensome compared with maintenance of the heat exchangers. A licensee or applicant can choose to routinely maintain the heat exchangers instead of testing them. Either the frequency of maintenance or the frequency of testing should be determined to ensure that the equipment will perform the intended safety functions during the intervals between maintenances or tests.

E. Schedule

1. In an effort to minimize the amount of time that a single, redundant division of safety-related equipment is out of service some utilities employ a "divisional outage" concept for major planned plant outages. By utilizing this concept significant maintenance work activities, i.e., system flow balance test, standby D/G [diesel generator] teardowns, electrical distribution bus work, etc., are performed on an alternating outage schedule for each division. This permits comprehensive maintenance on each division to be performed while reducing the overall impact on redundant safety system availability.

   The ability of a utility to implement and maintain a service water heat removal capability monitoring program would be significantly enhanced by the installation of permanent plant monitoring equipment. Installation of dedicated monitoring equipment would also reduce the impact of future testing on service water and heat exchanger availability.

   For a utility that employs the "divisional outage" concept and wishes to install permanent plant equipment to perform the system testing identified in Generic Letter 89-13, is it permissible to defer baseline data acquisition for one division of the service water system until the second refueling outage following the issuance of the generic letter? (Mississippi Power and Light)

   Answer

   This request appears to be reasonable for good cause. Any request for an adjusted schedule should be arranged through the appropriate project manager in the Office of Nuclear Reactor Regulation (NRR) of the NRC.

2. In reference to Recommended Action II of Generic Letter 89-13. (Niagara Mohawk Power)

   Asking an item of clarification Do all safety-related heat exchangers connected to or cooled by service water or raw water have to be tested or verified clean by maintenance, to insure satisfaction of the heat removal requirements, prior to plant startup following the first refueling outage beginning 9 months or more after the issuance of Gen. Ltr 89-13?

   Answer

   Yes.

   Reason for asking If a heat exchanger was cleaned 13 or possibly 18 months prior to issuance of Gen. Ltr 89-13 and found to be clean or tested and found acceptable and the current program does not call for recleaning or testing for 3 years then the program would have to be revised. Also trend data may already exist indicating that there is no need to clean or test on less than a 5-year interval. [This would also hold] if the heat exchanger is part of a larger component that is not scheduled for maintenance.

Answer

The generic letter is designed to provide flexibility in determining a justifiable alternative program for testing. The goal of the letter is to ensure that the heat removal requirements for the service water system are satisfied.

F. Closed-Cycle Systems

1. What is really required by the sentence on adequacy of chemistry control programs in the first paragraph of page 5 of the generic letter? (Kansas Gas and Electric)

Answer

Even though a closed cooling loop may contain water with controlled chemistry, the loop might be contaminated as a result of inleakage, inadequate chemistry controls, or materials in the system before the current chemistry control program became effective. An example of this was recently disclosed at the EPRI Service Water System Reliability Improvement Seminar at Charlotte, North Carolina, on November 6-8, 1989. In the internal study discussed there, optical examination of the primary side of the decay heat removal (DHR) heat exchanger (HX) tubes disclosed no fouling. The tubes were shiny bright. Optical examination of the closed component cooling water (CCW) HX, however, disclosed significant fouling. The tubes did not reflect any light. The problem was a paraffin-based packing material inadvertently left in the system when the plant was being constructed.

Suppose the licensee in this case can argue that it has a chemistry control program for water circulating through the CCW HX, but cannot show that the program has been in place since the system was filled initially. A proper response to the generic letter then would include testing the CCW HX. At any point in the program, if a finding of degraded heat transfer cannot be explained or remedied by maintenance in the open-cycle portion of the system, as would be possible in this case, the CCW HX should be tested and, depending on those results, the DHR HX should be tested. The process should be continued until the problem is remedied.

2. Does our CCWS [component cooling water system] need to be addressed as part of our response? We have recently shown, through eddy current testing of the CCW HTX's [heat exchangers], that the physical barrier between SW [service water] and CCW is adequate. Makeup to the CCW is via makeup water. (Wisconsin Public Service)

Answer

Not necessarily. See the answer to the previous question.

3. Page 5, paragraph 1. What level of documentation is required to justify excluding closed-cycle system heat exchangers from testing to verify heat transfer capability? (Portland General Electric)

Answer

The goal of the generic letter is to obtain assurance that the heat removal requirements for the service water system are satisfied. To exclude a closed-cycle system heat exchanger from testing, a licensee or applicant should show that the chemistry of the primary fluid and the heat transfer characteristics of the heat exchanger have been controlled since the system was first filled.

4. The ACRS [Advisory Committee on Reactor Safeguards] June 14, 1989, letter to the Commission noted five areas of concern with which NUBARG agrees. Some of the concerns were accommodated in the GL; however, we are interested to know the resolution of the following. (Nuclear Utility Backfit Action Reform Group [NUBARG])

   a. An intermediate closed cooling water system is exempt from the GL provided it is not subject to significant sources of contamination, is chemistry controlled, and does not reject heat directly to a heat sink. However, the adequacy of the chemistry control program must be verified over the total operating history of the plant. The ACRS questioned whether the absence of an adequate water chemistry control system over any part of the operating history of a closed-cycle system was adequate justification for including the system within the scope of the GL. How did the staff resolve this concern?

      Answer

      The staff relaxed its position on including closed-cycle cooling systems in Recommended Action II but added the precautionary recommendation that if degradation of heat transfer could not be explained or remedied by maintenance of the open-cycle part of the service water system, then testing may have to be selectively extended to the closed-cycle part of the system. See the answer to Question III.F.1.

   b. Are plants required to review closed cooling water system operating logs for the history of the plant to verify adequate chemistry control?

      Answer

      Licensees and applicants are required to assure that the safety-related heat removal requirements for the service water system are satisfied. If review of closed cooling water system operating logs for the history of the plant can help provide this assurance, then that review would be an acceptable part of the program.

G. Miscellaneous

1. Do both emergency service water systems and normal service water systems need to be reviewed? (Kansas Gas and Electric)

Answer

In some cases this may be necessary. The NRC is concerned about the safety-related effects of both systems. Sometimes the mode of operation of a service water system is changed under emergency conditions. This change may result in the introduction of uncontrolled water and thus the potential introduction of biofouling agents, corrosion products, and silt that may adversely affect the heat transfer performance of the system.

2. Page 6, paragraph 1. The generic letter does not specifically address testing of automatic safety features actuation which may be required to provide the required service water flow to safety-related heat exchangers. Does the NRC have any recommendations on functional tests of systems? (Portland General Electric)

Answer

The generic letter was written with the tacit assumption that all other regulatory conditions would be observed. In particular, functional testing required by technical specifications must be accomplished independently of the recommended actions of the generic letter. Where there is overlap, credit may be taken for the functional tests required by the technical specifications. The procedures, results, and considerations of such tests should be documented with the response to the generic letter and retained in appropriate plant records.

3. Recommended Action II paragraph 4 states tests should be performed following corrective action. Would bulleting tubes be considered as corrective actions? (Unidentified)

Answer

Yes.

4. Generic Letter 89-13 states that tests should be performed on heat exchangers before and after "corrective action" is performed. What is meant by "corrective action"? (Southern California Edison)

Answer

Corrective action is any action that improves the condition of the heat exchanger.

IV. ACTION III - ROUTINE INSPECTION AND MAINTENANCE

A. Recommendation III states, "Ensure by establishing a routine inspection and maintenance program . . . that corrosion, erosion . . . cannot degrade the performance of the safety-related systems supplied by service water." [Emphasis added.] It would seem unrealistic to assume that a program could be developed that will ensure absolutely no degradation of the system. Could you clarify that the intent here is to establish a program which will ensure that the system cannot degrade to the point at which its ability to perform its safety function is impaired? (Duke Power)

Answer

The NRC staff concurs in this interpretation.

B. Must all safety-related service water piping be cleaned or only the piping that is susceptible to corrosion buildup, i.e., low flow areas? Nondestructive examinations would be used to confirm the areas needed to be cleaned. (Wisconsin Public Service)

Answer

Recommended Action III is intended to provide assurance that the performance of open-cycle service water piping and components is not degraded as a result of corrosion, erosion, protective coating failure, silting, and biofouling. Once this assurance is made, the routine maintenance and inspection program can concentrate on those piping segments that are susceptible to these problems.

C. Would it be considered acceptable to omit from inspection piping which is practically inaccessible (i.e., underground piping) based on inspections of practically accessible piping? (Philadelphia Electric)

Answer

Inaccessibility itself would not be a sufficient reason for not inspecting piping. However, if additional justification including operational data and prior history is available, along with an evaluation that clearly shows that inspections would not be necessary, then inspection could be omitted.

D. Refer to Item III. Does the maintenance program have to include sampling of any crud or sediment found to determine its source; e.g., during routine maintenance a small amount of sediment was cleaned from a heat exchanger and the only documentation stated that it appeared to be a normal corrosion deposit? (Niagara Mohawk Power)

Answer

If the maintenance program can ensure that the heat removal requirements for the service water system are met, then it is acceptable. The better the root cause analysis of a problem is, however, the more effective will be the corrective action.

E. Refer to Item III. If minimum fouling is found during maintenance it should be acceptable to assume that the heat exchanger can still perform to the original design specification. Does the NRC have a problem with this assumption? (Niagara Mohawk Power)

Answer

The NRC staff cannot judge the adequacy of heat transfer capability based on the broad statement of "minimum" fouling. The licensee or applicant must determine what fouling level requires corrective action and justify the approach taken.

F. Under Specific Action III(A) on page 6 of the GL, what constitutes excessive accumulations of biofouling agents, corrosion products, and silt? (Nuclear Utility Backfit Action Reform Group [NUBARG])

Answer

The staff does not have a quantitative criterion for this parameter. If such accumulations degrade the heat transfer capability of the system such that the system cannot perform its safety-related function as shown by performance trend data, then such accumulations are excessive.

G. Are plant work requests adequate relevant documentation to support the inspection and maintenance documentation requirement of Specific Action III? (NUBARG)

Answer

Yes, as long as they can be made available to an NRC inspector.

H. Programs acceptable to the NRC in response to GL 89-13 Actions I and II were identified. What are some examples of acceptable inspection and maintenance programs in response to Action III? (Commonwealth Edison)

Answer

The NRC has not defined an acceptable program for Action III. However, the generic letter is designed to give the licensee or applicant sufficient flexibility in developing an appropriate program.

V. ACTION IV - SINGLE-FAILURE WALKDOWN

A. To what extent does this walkdown have to be performed? We are presently conducting a design-basis documentation reconstitution effort. A system walkdown is performed only if a problem is identified during documentation review. Walkdowns are not conducted all the time and are not full scope. Is the intent to complete walkdowns as required to ensure the system meets the licensing basis for the plant or to verify the as-built condition? (Public Service Electric and Gas)

Answer

The intent of the recommended action is to verify that the as-built condition of the system is sufficient to ensure performance of the intended function of the service water system. A design-basis reconstitution suffices for the walkdown inspection recommended here.

B. A service water system walkdown inspection was completed in 1986 at our plant. Can we take credit for that effort for this action or must we repeat it now to meet the 2-year criterion? (Niagara Mohawk Power)

Answer

You may take credit for the 1986 walkdown to meet this recommended action. The suggested time of 2 years to qualify the word "recent" was not meant to be rigidly interpreted. The NRC is interested in the walkdown being done now or recently, not in the distant past.

C. Does the system walkdown take into account piping, valves, and in-line components? What about cabling walkdown? Is our 79-14 walkdown sufficient to address this? (Wisconsin Public Service)

Answer

The system walkdown should ensure that the system's safety-related function can be accomplished in the event of failure of a single active component. Cabling walkdowns are thus not in the scope of Generic Letter 89-13. The intent of Recommended Action IV is to make maximum use of other pertinent activities in reviewing the system, but it is not sufficient to depend on 10-year-old reviews to ascertain the condition of the system today. However, the staff understands that Bulletin 79-14, "Seismic Analyses for As-Built Safety-Related Piping Systems," is not closed at all plants; therefore, if the walkdowns have been done recently, they would be acceptable. Activities included in the Individual Plant Examination (IPE) program may also constitute an acceptable response to this recommended action.

D. Recommendation No. IV discusses system walkdown inspections. GPU Nuclear assumes that the intent of the walkdown is down to the level of the flow diagram only. Does the NRC agree with this assumption or do we intend for a more detailed walkdown? (GPU Nuclear)

Answer

See the answer to the previous question. Single-failure inadequacies can occur in control systems as well as equipment in which water flows. The staff notes that single-failure inadequacies have been found at some plants apart from routine surveillance procedures.

E. Page 6, paragraph IV. Are there any specific requirements which are new that should be added into existing single-failure analysis? Explain what is meant by "reconstitution of the design basis of the system is not intended." (Portland General Electric)

Answer

As discussed in the answers to the next two questions, the staff does not intend that the licensing basis of a given plant be changed. Recommended Action IV for single-failure walkdown was not designed to incorporate any new feature into existing single-failure analysis techniques. The phrase "reconstitution of the design basis of the system is not intended" refers to excessively difficult determinations of design data. For example, this may be the case for small skid-mounted heat exchangers that were purchased as piece parts of larger units of equipment and for which the vendor may not have provided design data to the licensee or applicant. It would be enough to demonstrate that the equipment module of which the heat exchanger is a part could do its job.

F. Please elaborate on the requirements of Item 4. Specifically, what is intended by confirmation of the performance of the service water system in accordance with the design basis, without a reconstitution of the design basis? Also, is it intended by this requirement to perform a complete single-failure analysis of the service water system? (Northeast Utilities)

Answer

The licensee or applicant is expected to confirm that the installed as-built system satisfies the design requirements stated in the plant's licensing basis, that is, the final safety analysis report (FSAR), the technical specifications, and licensing documentation. See the answers to Questions V.C and V.D.

G. The generic letter states that the licensee should verify that the service water system is in accordance with the licensing basis of the plant. Is the licensing basis, in the context of this generic letter, considered to be the FSAR and tech specs [technical specifications] or will a more expansive interpretation be used? (Wisconsin Electric Power)

Answer

The licensing basis is as defined in the FSAR, technical specifications, and other licensing documentation. It is not the staff's intent that the licensing basis be redefined when addressing Generic Letter 89-13.

H. With regard to Action IV which requests confirmation that the service water system will perform its intended function in accordance with the licensing basis for the plant, which specific licensing basis must be reconfirmed at this time? Only the single active failure review? (Commonwealth Edison)

Answer

The licensing basis is considered to include the FSAR, technical specifications, and licensing documentation. See the answers to the previous two questions.

I. Action item 4 of GL 89-13 states that system walkdown inspections are required to confirm the as-built configuration of the service water systems. As a recently licensed plant, we are confident that our configuration control program satisfies this requirement. We believe system walkdowns are unnecessary for STPEGS [South Texas Project Electric Generating Station]. (Houston Lighting and Power)

Answer

This position appears to be reasonable for good cause. Ongoing programs that contain results pertinent to Generic Letter 89-13 should be referenced in the response as justification for an equally effective program and retained in appropriate plant records.

J. If other design-related issues are being addressed by other regulatory actions is it acceptable to exclude them from the scope of review for Action IV? (Commonwealth Edison)

Answer

Yes. See the answer to the previous question.

K. Should the single-failure analysis of the SW system include motive power (electrical/pneumatic, etc.) to active components (motor, valve, etc.)? If so, should it be limited only to the delivery of the motive power to the component, and not the single-failure reliability of the motive power sources (i.e., do not need to do single-failure analysis on motive power system)? (Carolina Power and Light)

Answer

The licensee or applicant should consider single failures in power-operated equipment or components that are part of the service water system. Single failures in power supply systems themselves do not need to be considered under Generic Letter 89-13.

VI. ACTION V - PROCEDURES REVIEW

A. Please discuss what constitutes the desired response for Action Item 5. (Confirming the adequacy of maintenance practices, operating and emergency procedures, and training that involves the service water system). The letter states that the confirmation "should include" recent reviews of practices, procedures, and training modules. Please provide some guidance for performing an adequate review. Also, are there other actions which the NRC recommends as part of the confirmation? (South Carolina Electric and Gas)

Answer

The staff has no specific guidance on what procedures, training, and maintenance practices should be evaluated or revised. The intent of this item is to increase personnel awareness of the importance of the service water system with the aim of reducing human errors. Refer to the wording in Action Item V in Generic Letter 89-13. Personnel or procedural errors were identified in the Office for Analysis and Evaluation of Operational Data (AEOD) case study (NUREG-1275, Volume 3, November 1988) discussed in the generic letter as a significant cause of service water system failures and degradations. One acceptable response would be to review those maintenance practices, operating and emergency procedures, and training modules that pertain to the events listed in the appendices in the AEOD case study.

Enclosure 2

LIST OF RECENTLY ISSUED GENERIC LETTERS

Generic Letter No.	Subject	Date of Issuance	Issued To
88-20, SUPP. 2	ACCIDENT MANAGEMENT STRATEGIES FOR CONSIDERATION IN THE INDIVIDUAL PLANT EXAM PROCESS	04/04/90	ALL HOLDERS OF OLs AND CPs FOR NUCLEAR POWER REACTOR FACILITIES
90-03	RELAXATION OF STAFF POSITION IN GL 83-28, ITEM 2.2, PART 2 "VENDOR INTER-FACE FOR SAFETY-RELATED COMPONENTS"	03/20/90	ALL POWER REACTOR LICENSEES AND APPLICANTS
90-02	ALTERNATIVE REQUIREMENTS FOR FUEL ASSEMBLIES IN THE DESIGN FEATURES SECTION OF TECHNICAL SPECIFICATIONS	02/01/90	ALL LWR LICENSEES AND APPLICANTS
90-01	REQUEST FOR VOLUNTARY PARTICIPATION IN NRC REGULATORY IMPAC SURVEY	01/18/90	ALL LICENSEES OF OPERATING REACTORS & CONSTRUCTION PERMITS FOR LWR NUCLEAR POWER PLANTS
89-23	NRC STAFF RESPONSES TO QUESTIONS PERTAINING TO IMPLEMENTATION OF 10 CFR PART 26 - GENERIC LETTER 89-23	10/23/89	ALL HOLDERS OF OPERATING LICENSEES AND CONSTRUCTION PERMITS FOR NUCLEAR POWER PLANTS
89-22	POTENTIAL FOR INCREASED ROOF LOADS AND PLANT AREA FLOOD RUNOFF DEPTH AT LICENSED NUCLEAR POWER PLANTS DUE TO RECENT CHANGE IN PROBABLE MAXIMUM PRECIPITATION CRITERIA DEVELOPED BY THE NATIONAL WEATHER SERVICE (GENERIC LETTER 89-22)	10/19/89	ALL LICENSEES OF OPERATING REACTORS AND HOLDERS OF CONSTRUCTION PERMITS (EXCEPT BYRON BRAIDWOOD, VOGTLE, SOUTH TEXAS, AND RIVER BEND)
89-21	REQUEST FOR INFORMATION CONCERNING STATUS OF IMPLEMENTATION OF UNRESOLVED SAFETY ISSUE (USI) REQUIREMENTS	10/19/89	ALL HOLDERS OF OPERATING LICENSES AND CONSTRUCTION PERMITS FOR NUCLEAR POWER REACTORS

April 4, 1990

TO: ALL HOLDERS OF OPERATING LICENSES OR CONSTRUCTION PERMITS FOR NUCLEAR POWER PLANTS

SUBJECT: SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT (GENERIC LETTER 89-13, SUPPLEMENT 1)

On July 18, 1989, the U.S. Nuclear Regulatory Commission (NRC) issued Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." On October 23, 1989, the NRC announced in the Federal Register that it would hold four workshops on this generic letter. The NRC conducted these workshops in Philadelphia, Atlanta, Chicago, and Denver on November 28 and 30 and December 5 and 7, 1989, respectively. The NRC answered written questions submitted through appropriate project managers in the Office of Nuclear Reactor Regulation before the first workshop and questions submitted at each workshop. Transcripts of these meetings are available in the NRC Public Document Room, 2120 L Street NW, Washington, DC.

This supplement contains the questions and answers read into the transcripts during the workshops, except for the following changes. Questions received in the general, Action I, and Action II categories have been grouped according to topic. In addition, the NRC staff modified some answers after the workshops with the aim of furnishing additional guidance. Please contact the project manager if you have questions on this matter.

Sincerely,

Original signed by
James G. Partlow

James G. Partlow
Associate Director for Projects
Office of Nuclear Reactor Regulation

Enclosures:
1. Questions and Answers
2. List of Recently Issued NRC Generic Letters

Technical Contact: C. Vernon Hodge, NRR
(301) 492-1169

DISTRIBUTION w/enclosures

TEMurley, NRR	JHSniezek, NRR
FJMiraglia, NRR	JGPartlow, NRR
CERossi, NRR	CHBerlinger, NRR
CVHodge, NRR	JACalvo, NRR
PBaranowsky, NRR	PDR
Central Files	DCB
DOEA R/F	OGCB R/F
VHodge R/F	

Document Name: GEN LTR 8913 SUPP 1
*SEE PREVIOUS CONCURRENCES

			ADP/NRR	
			JGPartlow	
			03/27/90	
*OGCB:DOEA:NRR	*RPB:ARM	*C/OGCB:DOEA:NRR	*D/DOEA:NRR	ADT/NRR
CVHodge	TechEd	CHBerlinger	CERossi	FJMiraglia*
01/10/90	01/03/90	01/10/90	01/19/90	03/27/90