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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD '94 FEB 25 P3:46

In the matter of Pacific Gas and Electric Company	)	Docket Nos. 50-275-OLA 50-323-OLA -2
Diablo Canyon Nuclear Power Plant	)	Construction Period Recovery
Units 1 and 2	)	
	)	February 25, 1994

SAN LUIS OBISPO MOTHERS FOR PEACE'S MOTION TO REOPEN THE RECORD REGARDING PACIFIC GAS AND ELECTRIC COMPANY'S APPLICATION FOR A LICENSE AMENDMENT TO EXTEND THE TERM OF THE OPERATING LICENSE FOR THE DIABLO CANYON NUCLEAR POWER PLANT

I. INTRODUCTION

Pursuant to 10 C.F.R. § 2.734, San Luis Obispo Mothers for Peace ("SLOMFP") hereby moves to reopen the record in this construction period recapture proceeding for Pacific Gas & Electric Company's ("PG&E's") Diablo Canyon nuclear power plant ("DCNPP"). SLOMFP seeks to reopen the record for the purpose of introducing recently issued Nuclear Regulatory Commission ("NRC" or "Commission") Inspection Report 93-36 (January 12, 1994) (Attachment 1). This report contains significant new evidence which suggests that PG&E's maintenance of the plant's vital Auxiliary Saltwater ("ASW") system may be seriously inadequate; that maintenance was so deficient that the ASW system may have been nonfunctional during the summer months; and that PG&E may have made false representations to the NRC regarding the maintenance and operability of its ASW system.[1]

As described more fully below, SLOMFP satisfies the applicable criteria for reopening the record to introduce this new evidence. First, this motion is timely filed since it concerns a recently issued NRC inspection report, and thus could not have been raised before the record closed. Second, the new evidence raises significant safety and environmental issues because it concerns the adequacy of PG&E's ASW cooling system, which performs the essential safety function of cooling the reactor during certain design basis accidents, and because the deficiencies and misrepresentations of PG&E with respect to this system raise concerns about PG&E's overall maintenance and surveillance program. Finally, this new evidence is likely to affect the outcome of the case because it contradicts testimony at the hearing by PG&E and the NRC staff and because it corroborates many aspects of MFP's position that PG&E's maintenance and surveillance program is inadequate. Moreover, the fact that PG&E appears to have misrepresented the operability of the ASW system and the status of

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1 SLOMFP notes that the NRC has not yet "resolved" many of the issues raised in Inspection Report 93-36, and is still pursuing its inquiry. Thus, full litigation of the issues raised by Inspection Report 93-36 may have to await the NRC's resolution of these issues. However, the Licensing Board need not wait until the NRC takes final enforcement action to consider whether the record of this licensing case should be reopened to consider the issues raised by Inspection Report 93-36, because the Inspection Report now provides sufficient factual information on which to proceed.

its maintenance program implicates the integrity of PG&E's entire maintenance and surveillance program and the reliability of PG&E's testimony in this case.

II. BACKGROUND

A. The License Extension Proceeding

On July 9, 1992, PG&E applied for an operating license amendment to extend the term of its operating license for Unit 1 and Unit 2 so that the plant would have a full 40-year operating license term, starting from the dates that the operating licenses were issued for Units 1 and 2. SLOMPF timely petitioned to intervene and a hearing was held in August of 1993 on the issues raised by SLOMFP's two admitted contentions, including the adequacy of PG&E's maintenance and surveillance program. SLOMFP introduced extensive evidence, in the form of PG&E correspondence, NRC inspection reports, and other documents, demonstrating a repetitive pattern of inadequacies in PG&E's maintenance program. The parties submitted Proposed Findings of Fact and Conclusions of Law, which are now under consideration by the Licensing Board.

B. Safety Significance of and Regulatory Requirements for The Auxiliary Salt Water System

One of the essential safety systems at DCNPP which must be monitored and maintained to ensure its adequate performance is the ASW system, also known as the service water system. The ASW system performs an important safety function because it serves as the "ultimate heat sink" for removal of heat from safety components in the event of a design basis accident. See Generic Letter 89-13, "Service Water System Problems Affecting Safety Related Equipment" (July 18, 1989), citing 10 C.F.R. Part 50, General Design Criterion ("GDC") 44 (Attachment 2).

Adequate surveillance and maintenance of the ASW system are specifically required by NRC regulations. Thus, the service water system must be designed "to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system." Id., citing GDC 45. It must also be designed "to permit appropriate periodic pressure and functional testing." GDC 46. NRC regulations at 10 CFR Part 50, Appendix B, Section XI, also require 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."

C. Generic Letter 89-13

On July 18, 1989, the NRC issued Generic Letter 89-13, which described recurring industry problems related to "biofouling" of service water systems with large organisms such as clams and mussels ("macrofouling"), and small organisms such as algae ("microfouling"); as well as fouling by other agents such as mud, silt, and corrosion products. The generic letter requested that licensees and applicants follow five specific recommendations, or take "equally effective actions," to ensure that their service water systems comply and remain in compliance with GDC 44, 45, and 46, and 10 C.F.R. Part 50, Appendix B, Section XI. Id. at 4. These recommendations were:

> 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." . . .
>
> II. "Conduct a test program to verify the heat transfer capability of all safety-related heat exchangers cooled by service water." . . .
>
> 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." . . .
>
> IV. "Confirm that the service water system will perform its intended function in accordance with the licensing basis for the plant."
>
> 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."

Id. at 4-6. All licensees, including PG&E, were required to advise the NRC whether they had established programs to implement the recommendations or pursued "an equally effective alternative course of action." Id. at 7.

PG&E responded with a a detailed discussion of how it would either implement the recommendations of Generic Letter 89-13 or establish equivlalent alternatives. Letter No. DCL-90-027 (January 26, 1990) (Attachment 4). In late 1991, PG&E provided a supplemental response which "reported completion of the initial program actions." Letter No. DCL-91-286 (November 26, 1991) (Attachment 5).[2]

III. NEW EVIDENCE OF MAINTENANCE DEFICIENCIES AND SAFETY PROBLEMS IS IDENTIFIED IN INSPECTION REPORT 93-36.

On January 12, 1994, the NRC issued Inspection Report 93-36. The Inspection Report discussed the results of a routine, announced inspection conducted from December 13 through December 17, 1993, regarding "PG&E's activities performed in response to Generic Letter 89-13." Id., cover letter at 1. As discussed below, Inspection Report 93-36 identifies numerous deficiencies in PG&E's response to Generic Letter 89-13, and in its program for monitoring and maintaining the ASW system. Overall, the inspection revealed significant and extensive gaps, inaccuracies and weaknesses in PG&E's surveillance and testing of the system. PG&E also allowed the plant to operate in exceedance of its stan-

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[2] Previous to the issuance of Generic Letter 89-13, the NRC had also expressed "concern" regarding the adequacy of PG&E's ASW system in Inspection Report 88-11 (June 17, 1988) (Attachment 3). See Inspection Report 93-36, cover letter at 1. Inspection Report 88-11 criticized PG&E for "inadequate knowledge of the plant system design bases" with respect to the ASW system. Inspection Report 88-11, cover letter at 1-2. The NRC found that in numerous instances, the design basis assumptions for the ASW system had not been fully implemented into plant procedures and alarm set points, thus "requiring a review" of the ASW's past operability. Id., Details at 17. Moreover, plant configuration and procedures did not consistently conform to design basis assumptions. Id. at 18-10. In response to this inspection report, PG&E assured the NRC that the ASW system had "adequate margin." Inspection Report 93-36, cover letter at 1.

dards for taking heat Component Cooling Water ("CCW") exchangers out of service for cleaning. Moreover, one of the heat exchangers failed an important operability test. Of extreme concern is the fact that PG&E appears to have made two significant misrepresentations, on the operability of the system, and the completeness of its inspection program.

Because PG&E's surveillance program was inadequate, PG&E apparently did not recognize perform maintenance when it was necessary. Thus, for instance, PG&E did not discover through its own surveillance program that one of DCNPP's CCW heat exchangers had significant fouling, to the extent that it exceeded the margin of safety as specified by the manufacturer. Inspection Report 93-36, Details at 7. Rather, the fouling was found during the NRC's December 1993 inspection. Accordingly, as the NRC observed in Inspection Report 93-36, the "long-term operability of the ASW system" is in "question." Id., cover letter at 1.

A. Ongoing program for surveillance and control of biofouling inadequate

In response to Generic Letter 89-13's first recommendation for "an ongoing program of surveillance and control techniques to reduce the incidence of flow blockage problems as a re[illegible] of biofouling," PG&E committed to "visually inspect the ASW intake structure during refueling outages," "install a continuous chlorination system," and "continue [PG&E's] existing program for monthly system flow testing." DCL-90-027, Enclosure at 1-3 Inspection Report 93-36, Details at 3. In DCL-91-286, PG&E

stated that these commitments had been fulfilled. However, the NRC's December 1993 inspection revealed numerous deficiencies in PG&E's response to this recommendation.

First, PG&E did not follow its criteria for maintenance of the ASW structure. The NRC inspector noted that for several months in 1992, "the licensee temporarily allowed the heat exchangers to exceed their operational differential pressure limit of 140 inches, be declared inoperable and left in service until a limit of 200 inches was reached." Id.

Second, PG&E did not establish a permanent testing program, as it had promised. Although PG&E had committed to undertake an "ongoing" program for surveillance of the ASW system in 1990, almost four years later, the NRC's inspection revealed that PG&E was still using "temporary" test instruments for monthly flow tests of the ASW system, and that "Diablo Canyon does not have installed flow instrumentation available to the operators." Id.

Finally, PG&E used test acceptance values without obtaining review or approval by the NRC. The NRC found that the monthly flow tests of the ASW systems used revised acceptance criteria, and that the revisions "had not been reviewed by the NRC technical branches." Id., Details at 4.

B. Heat Exchanger Testing and Maintenance Inadequate

The CCW heat exchangers function to transfer heat from the primary coolant for plant safety systems to the service water or ASW cooling system. If they are blocked and unable to transfer heat from the safety systems at a sufficient rate, then the safety systems may fail. Thus, the operability of the CCW heat exchangers is extremely important to plant safety.

Accordingly, Generic Letter 89-13 "requested that licensees conduct a test program to verify the heat transfer capability of all safety-related heat exchangers." Inspection Report 93-36, Details at 4. The generic letter also "allowed for an alternative program such as frequent regular maintenance of the heat exchanger." Id. PG&E responded that it "would perform a one-time heat exchanger performance test to confirm the baseline heat transfer capability of the heat exchangers," and that it would "implement an alternative program to verify the system would remain capable of maintaining design basis capability." DCL-90-027, Enclosure at 4; Inspection Report 93-36, Details at 4. DCL-90-027 also stated that the licensee would "implement a monitoring program which combined flow testing, trending, inspection, and frequent preventative maintenance." Id. PG&E committed to completing these actions by the end of the 1991 fourth refueling outage of each unit. Id., Details at 5.

In DCL-91-286, PG&E reported that it "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." Id., Enclosure at 2. PG&E also stated that the licensee "had implemented the alternative monitoring program." Id.

However, as discussed below, in reviewing PG&E's two-pronged program for assuring heat exchanger operability -- i.e. initial testing and subsequent preventative maintenance -- the NRC found that PG&E had falsely stated that the heat exchanger passed the test, that the operability of the heat exchangers was not "established" by PG&E's "program for heat exchanger preventative maintenance, trending, inspection, and flow testing," and that indeed, one of the heat exchangers had so much tube fouling or plugging that it exceeded the manufacturer's standard for safe performance.

1. PG&E Misrepresented Results of Heat Exchanger Test

Inspection Report 93-36 found that PG&E had not reported accurately when it stated in DCL-91-286 that its computer model "predicted that the heat exchangers would remove the design basis heat load at design conditions." Id., Details at 5, DCL-90-027, Enclosure at 2. Instead, the inspector's review of a report of a field test performed on February 2, 1991 (Field Test Report 420DC-91.1156) showed the heat removal capacity for heat exchanger CCW 1-2 to be 98.7 percent of the design, i.e., lower than the design basis capacity. Id. The inspector "also determined that the differential pressure across the heat exchanger was probably at only 101-104 inches based on informal records. Therefore, the heat removal capacity would have been less if the licensee had accounted for the maximum allowed differential pressure of 140 inches." Id.

2. **Heat Exchanger Testing Deficient**

The NRC inspector also found numerous deficiencies in the conditions and assumptions used for the one time heat exchanger test. According to the NRC, PG&E did not establish "several important initial conditions" for the test, including the following:

First, there was no assessment of the amount of microfouling and macrofouling already present in the heat exchangers, resulting in an approach that was "not conservative." Id., Details at 5. Second, PG&E had not recorded the amount of differential pressure present in the heat exchanger, thus precluding the use of the test data to assess the adequacy of the operator's differential pressure limits. Id. Finally, PG&E did not measure the outlet water box level, which affects the measurement of differential pressure across the heat exchanger because it varies with the tide. Id.

The NRC also found that PG&E had used a computer code for the field test which was not validated for accuracy. Id., Details at 11. The NRC also considers this issue to be an "unresolved item." Id.

3. Heat Exchanger Maintenance Program Inadequate, Rendering Operability Uncertain

In its initial response to Generic Letter 89-13, PG&E noted that the one-time heat exchanger performance test was subject to significant uncertainties, and would not necessarily be conclusive. DCL-90-027, Enclosure at 4. Therefore, PG&E relied heavily on its ASW monitoring program as "an alternative method which will ensure that the ASW system operates within its design basis." Id. However, the NRC's inspection revealed that PG&E had not assured that "maintenance and surveillance controls" were "sufficient to ensure system operability." Inspection Report 93-36, Details at 2. In particular, PG&E's setpoint for taking heat exchangers out of service for cleaning of macrofouling was "excessive," allowing significant fouling to occur before cleaning took place. In fact, the inspector determined that because of this excessively high setpoint, "the heat exchangers may have been inoperable during conditions of warmer ocean temperatures." Id., Details at 7 (emphasis added). Moreover, PG&E itself reported to the NRC on December 30, 1993, that on August 23, 1990, and perhaps prior to and subsequent to that date, the CCW heat exchangers may have had sufficient fouling to have precluded the systems from meeting their design basis. Id., Details at 9.

Although PG&E also concluded in an "operability assessment" that the heat exchangers were operable after PG&E instituted continuous chlorination in 1992, this conclusion is suspect, given the many deficiencies found by the NRC in PG&E's program for monitoring and assessing the operability of the heat exchangers.[3] According to the Inspection Report, PG&E took heat exchangers out of service for cleaning of macrofouling accumulations when the differential pressure across the heat exchanger reached 140 inches of water. Id. at 6. However, the NRC inspector could find no basis for this setpoint in the documents provided by PG&E. Id. In order to "make an independent engineering judgment" as to the adequacy of this setpoint, the NRC examined CCW Heat Exchanger 2-1, which PG&E had taken out of service at a differential pressure of 125 inches. Because of other fouling problems in this heat exchanger due to calcification, CCW 2-1 was expected to show less macrofouling than other heat exchangers at the same differential pressure.

However, this expectation was not borne out by the NRC's inspection. At 125 inches, CCW 2-1 had significant fouling, including 15 tubes plugged with mussels and barnacles; and three crabs in the head, representing another three plugged tubes. Id. All together, including ten tubes that were permanently plugged due to tube wear problems, the inspector estimated that 28 tubes were plugged. This exceeded the manufacturer's plugging limit for safe operation of 2 percent of the total tubes or 24 pluggable tubes. Id. The NRC found that the inadequate setpoint and

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3 Neither PG&E's December 30, 1993 report nor the operability assessment were available in the NRC's Public Document Room at the time of this writing; thus SLOMFP was unable to evaluate them.

resultant inoperability of the heat exchangers is a "significant item due to the high safety significance of the system." Id. at

4. Lack of Trending for Calcification in CCW Heat Exchanger Tubes

According to Inspection Report 93-36, PG&E had observed calcification on the inner diameter of the CCW heat exchanger tubes, at the outlet end in the tube sheet area. Id. at 11. According to a system engineer, the calcification was caused by deposits from seawater caused by the impressed voltage system for cathodic protection of the ASW piping. Id. The engineer stated that "the calcification was of a short length and would not affect the available heat transfer area or tube fouling factor." Id. However, the NRC inspector "expressed the concern that since the buildup was not being trended for rate of buildup, and since the inlet of the tubes had a reduced diameter, the calcification 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." Id. The NRC considers the effect of the calcification on the heat exchanger capacity and the potential effect of undetected tube plugging to be a "followup item." Id.

C. PG&E Failed to Take Any Corrective Action In Response to ASW Problems.

The NRC found "significant" the number of previous opportunities PG&E had to address the issue of improper setpoints for differential pressure, but failed:

> System operability concerns due to differential pressure had been raised in Inspection Report 50-275/88-11 and 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 and maintenance practices. The failed heat exchanger capacity test in 1991 should have triggered investigative actions but did not. Finally, a QA surveillance in May 1993 (discussed in Section 3 of this report) raised the specific issue of the adequacy of the differential pressure setpoint, but did not elicit a studied response from the engineering organization. These multiple missed opportunities indicate that engineering was ineffective.

Id., Details at 7. PG&E's "apparent failure to establish adequate differential pressure limits to ensure CCW heat exchanger operability" remains an "unresolved item pending the licensee's assessment of operability and the inspector's review of that assessment." Id.

Inspection Report 93-36 also criticizes PG&E's failure to resolve -- or even to document -- the February 2, 1991, heat exchanger test failure, despite numerous reminders that it needed to do so. Id., Details at 10. The test failure apparently was not documented until November 22, 1991, almost ten months later. PG&E did nothing in response; in fact, it falsely reported to the NRC on November 26, 1991, that the computer model used in the test had predicted that the heat exchangers would carry the design basis heat load. See discussion in section III.B.1 above.

PG&E's QA Department also conducted an audit from March 5 to May 7, 1993 and issued a formal Action Request on May 10, 1993. Inspection Report 93-36, Details at 10. The audit report, issued

July 28, 1993, identified the test failure of CCW Heat Exchanger 1-2, as well as a "concern with the 140 inch differential pressure setpoint." Id. However, almost two years after the test failure, during the NRC inspection in the middle of December 1993, the effect of the test failure on ASW system reliability was still unresolved.

D. PG&E Falsely Told NRC It Had Established a Routine Inspection Program for ASW System

As discussed above, one of Generic Letter 89-13's recommendations was for the establishment of "a routine inspection and maintenance program for the service water system piping and components" so that "corrosion, erosion, coating failure, silting and biofouling would not degrade the performance of the system." Id. at 7. In DCL-90-027, PG&E committed to establishing such a program by the fourth refueling outages for Units 1 and 2, and in DCL-91-286, it stated that the program had been established. See Inspection Report 93-36 at 8; DCL-90-027, Enclosure at 5; DCL-91-286, Enclosure at 2.

However, the 1993 inspection revealed that contrary to its previous assurances, PG&E had not established a routine inspection program or procedures for the ASW piping. Inspection Report 93-36, Details at 8. During the 1991 refueling outages, PG&E inspected only about half the ASW piping, using a "temporary procedure."[4] Id. No ASW piping inspections were conducted during

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4 The inspection report also noted that PG&E had an open action request dated March 1991, which requested that the temporary inspection procedure be made a permanent plant procedure and that a regular period be established. However, the requested actions were never completed. Id.

the fifth refueling outage, and none were planned for the sixth outage in 1994. Id.

E. Lack of ASW Flow Instruments for Operator Information

It appears that one reason for PG&E's failure to give adequate maintenance attention to the ASW system is the lack of fflow indicators. According to the Inspection Report, the DCNPP operators "do not have ASW flow information available to the control room." Id., Details at 12. Moreover, for unspecified reasons, a flow instrument installed at the intake structure "does not indicate accurately," according to the system engineer. Id. The operators "infer flow from the differential pressure across the heat exchanger and by observing the electrical current to the ASW pump motors." Id. Although the NRC noted that there is no regulatory requirement for flow instrumentation, the matter "was discussed with the licensee at the exit interview." Id.

IV. SLOMPF HAS SATISFIED THE STANDARD FOR REOPENING THE RECORD.

As discussed below, SLOMFP satisfies the three criteria of 10 C.F.R. § 2.734(a) to reopen the record in this case.[5]

A. The Motion is Timely.

This motion is timely, because it could not have been filed before the record closed in August of 1993. The NRC's inspection was not conducted until December of 1993, and the Inspection Report was not issued until January 12, 1994. SLOMPF has proceeded diligently, within a reasonably short period of time of receiving the Inspection Report, to review and evaluate the Inspection Report, to acquire and review all relevant and obtainable documents from the NRC's Public Document Room, and to set forth its concerns in this motion.

In addition, the motion is timely because it predates final enforcement action on the matters raised by Inspection Report 93-36. While SLOMFP believes that the Inspection Report provides sufficient basis for reopening the record now, the full factual scope of the reopened litigation cannot be established until the NRC has concluded its investigation of the issues raised in Inspection Report 93-36.

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5 In compliance with § 2.734(b), the motion is supported by the declaration of undersigned counsel, Diane Curran, who prepared this motion in reliance on the expertise of the NRC inspectors who conducted the December 1993 inspection and prepared Inspection Report 93-38, as well as the authority of Generic Letter 89-13.

B. The Motion Addresses a Significant Safety and Environmental Issue.

There can be no question that Inspection Report 93-36 raises issues of enormous safety and environmental significance. First, as stated by the NRC, the past operability of the CCW heat exchangers has not been established by PG&E's maintenance and surveillance program. Id. at 2. Moreover, the issues raised in the Inspection Report may have an impact "upon the future operability of the ASW system." Id., cover letter at 1. The potential inoperability of the ASW system and associated heat exchangers at Diablo Canyon has extremely high safety significance. If this cooling system is inadequate to remove heat from safety systems during an accident, those safety systems may be rendered inoperable as a result, with disastrous consequences. In fact, the definition of "operability" contained in NRC Standard Technical Specifications for Westinghouse plants provides that a system or component may only be considered "operable" when all "other auxiliary equipment" that is required for that system or component, including cooling water, is "also capable of performing [its] related support functions." NUREG-1431 (September 1992). Thus, PG&E has no basis for relying on safety systems cooled by the CCW heat exchangers and and ASW system if those cooling systems are inoperable.

Moreover, the nature of PG&E's response to Generic Letter 89-13 and to identified problems with the ASW system also raises significant safety issues. As the NRC observed, it is "significant" that PG&E had "a number of opportunities" to address the ASW problem, but did not. Id. Such laxness demonstrates a lackadaisical attitude toward maintenance of key safety systems.

PG&E's response to Generic Letter 89-13 also misrepresented the facts on two important issues: the results of the single heat exchanger test that played an important role in PG&E's program for assuring the adequate operability of the heat exchangers; and the existence of an inspection program for the ASW piping. Whether they result from incompetence or intentional deception, such misrepresentations raise questions about the adequacy and integrity of PG&E's entire maintenance program.

C. The admission of this newly proffered evidence is likely to affect the outcome of this case.

The evidence described above is likely to affect the outcome of this case, because it contradicts the testimony and proposed findings of PG&E and the NRC Staff in several important respects, because it provides significant corroboration for the proposed findings of SLOMFP, and because it raises significant questions with respect to the PG&E's competence and integrity in responding to maintenance problems. For instance:

1. PG&E and NRC Testimony and Proposed Findings on the Adequacy of PG&E's Maintenance and Surveillance Program Are Contradicted by Inspection Report 93-36.

PG&E's and the NRC Staff's testimony in this case are directly contradicted by the findings in Inspection Report 93-36. For instance, the NRC Staff testified that the "performance of maintenance and surveillance at Diablo is considered to be superior and clearly supportive of safe facility operation." NRC Staff Testimony of Paul P. Narbut, Mary H. Miller and Sheri R. Peterson Regarding Contention 1: The Surveillance and Maintenance Program at Diablo Canyon at 5 (July 30, 1993). The NRC also testified that "generally the Licensee has dealt with problems in the maintenance and surveillance areas effectively," and has "corrected a great majority of the problems promptly." Id. at 6. The Staff's Proposed Findings and Conclusions of Law also assert that "in-service inspections are being carried out in an appropriate manner." NRC Staff's Findings of Fact and Conclusions of Law at 50 (December 22, 1993). Similarly, PG&E testified that PG&E has "a comprehensive maintenance and surveillance program," which it has implemented in "an effective, and often outstanding, manner." Testimony of Pacific Gas & Electric Company Addressing Contention I: Maintenance and Surveillance at 3, 4 (August 2, 1993). See also PG&E's Proposed Findings of Fact and Conclusions of Law at 57-63.

These broad and sanguine generalizations contrast starkly with the reality presented by Inspection Report 93-36, in which PG&E has allowed an essential safety system to deteriorate and perhaps become inoperable because it failed to conduct adequate surveillance, tested equipment improperly, failed to follow up on a significant test failure, failed to establish adequate criteria for taking heat exchangers out of service to conduct maintenance, and ignored even the weak criteria that it had by allowing the plant to operate when setpoints were exceeded. Moreover, it ignored these problems for a period of years, rather than addressing them in a timely fashion.

2. The Inspection Report Corroborates SLOMFP's Proposed Finding That Deficiencies in PG&E's Maintenance and Surveillance Program at Diablo Canyon Have Resulted in the Failure or Unreliability of Important Safety Systems.

In its Proposed Findings, SLOMFP accurately observed that most of PG&E's maintenance problems in the last several years have disabled or threatened essential safety systems, thus undermining the redundancy of the systems and reducing the margin of safety on which the plant relies for safe operation. See SLOMFP Proposed Findings, pars. 25, 26. As established by Inspection Report 93-36, the ASW system is another vitally important safety system whose operability has been compromised by inadequate surveillance and maintenance. Not only did the CCW heat exchanger fail the initial test of its capacity, but inspection of one heat exchanger revealed that tube plugging due to biofouling and other causes exceeded PG&E's own acceptance criteria. Moreover, not only is PG&E's setpoint for determining when maintenance should be conducted too high, but PG&E sometimes allows the plant to continue operating in exceedance of the setpoint. See discussion above at 8. Thus, the operability and reliability of the ASW system are in doubt. See Inspection Report 93-36, Details at 2.

3. The Inspection Report Corroborates SLOMFP's Proposed Finding That PG&E Has Shown a Pattern of Untimely or Ineffective Response to Maintenance Problems.

As discussed in section II.C. above, despite repeated opportunities or reminders to take action, for years PG&E ignored both the inadequacy of its setpoint for maintenance on the CCW heat exchangers, and the 1991 heat exchanger test failure. Moreover, it still had not resolved these problems when the NRC conducted its inspection in late 1993. In fact, PG&E mispresented the results of the heat exchanger test rather than taking steps to address the failure. PG&E's dismal performance in this regard corroborates SLOMFP's proposed finding, based on numerous other similar examples, that PG&E has shown a pattern of responding to many maintenance problems in a lax and untimely manner. See SLOMFP's Proposed Findings of Fact and Conclusions of Law, par. 33 (November 19, 1993). It also makes a mockery of the NRC Staff's testimony and proposed finding that DCNPP's maintenance and surveillance programs "had elements of 'openness' and 'aggressive self-identification' which indicated that the programs were extremely healthy and effective." NRC Staff's Findings of Fact and Conclusions of Law In the Form of an Initial Decision, par. I-47 (December 22, 1993).

4. The Inspection Report Corroborates SLOMFP's Proposed Finding That Routine Surveillances, Tests and Inspections at DCNPP are Inadequate to Ensure the Continued Safe Operation of the Plant.

In its Proposed Findings, SLOMFP noted the extensive and repetitive pattern of missed surveillances, improperly performed tests, and a lack of monitoring activities for essential equipment at DCNPP. Id., pars. 49-52. As documented in Inspection Report 93-36, and discussed above, a single inspection of only one safety system at PG&E has revealed an extraordinary number of omissions and deficiencies with respect to routine surveillance and testing of the ASW system. This evidence thus provides significant support for SLOMFP's proposed finding regarding the general inadequacy of PG&E's routine surveillance and testing programs.

5. The Inspection Report Corroborates SLOMFP's Proposed Finding That a Lack of Communication and/or Coordination Leads to Inadequate Maintenance at Diablo Canyon.

As discussed in SLOMPF's Proposed Findings at page 22, the record of this case demonstrates a pattern of poor communication and coordination between various PG&E departments with maintenance-related responsibilities. Inspection Report 93-36 provides further significant support for this conclusion, noting the role of "management and communication" issues in the breakdown of ASW maintenance. Id., cover letter at 1. Inspection Report 93-36 portrays a total breakdown in communication between departments responsible for design, engineering, surveillance, and maintenance. As a result, the ASW system was not properly monitored or maintained, threatening the operability of the system and the health and safety of the public.

For instance, PG&E did not document the February 1991 failure of a CCW heat exchanger until November of that year. See discussion in Section C above. An Action Request was not submitted to the Engineering Department until May of 1993, and a QA report was not issued until July of 1993. There is no explanation for these great time gaps in communication. Moreover, the Inspection Report does not even state whether the Maintenance Department was made aware of the test failure.

It also appears that maintenance personnel, who would have had practical experience with the appropriateness of setpoints triggering maintenance of heat exchangers, were not consulted regarding problems with the acceptability of these setpoints. Moreover, if Maintenance had any concerns about the setpoints, they apparently were not communicated to the Engineering Department. Instead, the engineers preparing the DCM vaguely relied on heat exchanger maintenance "per standard practice" without having any understanding that (a) the ASW system was not being properly maintained or (b) the 140 inch setpoint was too high. Inspection Report 93-36, Details at 9.

6. The Inspection Report Raises Significant Questions With Respect to PG&E's Competence and Integrity in Responding to Maintenance Problems.

As discussed above, PG&E appears to have misrepresented the status of its maintenance and inspection program to the NRC in two significant respects. First, PG&E reported to the NRC that a heat exchanger test was successful, when in fact it failed. This test was significant because pursuant to PG&E's program for maintenance and surveillance of the ASW system, it formed part of PG&E's basis for assuring the operability of the ASW system. Second, PG&E told the NRC it had established a program for surveillance of ASW piping, when in fact it had not. These apparent misrepresentations raise grave questions about both the competence and the integrity of PG&E. Whether the misrepresentations resulted from ineptitude or intentional deceit, either cause would have serious implications regarding the adequacy of PG&E's maintenance and surveillance program, and the truthfulness and reliability of other representations it has made regarding that program, both in this proceeding and in responding to the NRC in the course of its oversight and enforcement activities.

CONCLUSION

For the foregoing reasons, the record of this proceeding should be reopened for the purpose of considering Inspection 93-36 and any other relevant evidence regarding PG&E's inadequate surveillance and maintenance of the ASW system.

Respectfully submitted,

Diane Curran

Diane Curran
Harmon, Curran, Gallagher
& Spielberg
6935 Laurel Avenue, Suite 204
Takoma Park, MD 20912
(301) 270-5518

DECLARATION OF DIANE CURRAN

1. I am the attorney representing San Luis Obispo Mothers for Peace in this proceeding.

2. I have reviewed Inspection Report 93-36 (January 12, 1994), Inspection Report 88-11 (June 17, 1988), Generic Letter 89-13 (July 18, 1989), DCL-90-027 (January 26, 1990) and DCL-91-286 (November 25, 1991).

3. The arguments set forth above regarding SLOMFP's satisfaction of the NRC's criteria for reopening the record of this case are based on the factual contents of the documents identified in paragraph 2 above, on the NRC's conclusions regarding the legal and safety significance of these facts, and on my own conclusions regarding the legal and safety significance of these facts.

Diane Curran

Diane Curran

February 25, 1994

Attachment 1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION V

1450 MARIA LANE
WALNUT CREEK, CALIFORNIA 94596-5368

January 12, 1994

Pacific Gas and Electric Company
Nuclear Power Generation, B14A
77 Beale Street, Room 1451
P. O. Box 770000
San Francisco, California 94177

Attention: Mr. G. M. Rueger, Senior Vice President and General Manager
Nuclear Power Generation Business Unit

Subject: NRC INSPECTION REPORT NOS. 50-275/93-36 AND 50-323/93-36

This refers to the routine, announced, inspection conducted by Mr. Paul P. Narbut during the period from December 13 through December 17, 1993. The inspection examined your activities as authorized by NRC License Nos. DPR-80 and DPR-82. At the conclusion of the inspection, the inspector discussed the inspection findings with Mr. John Townsend and other members of the PG&E staff.

The inspection 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. Areas examined during this inspection are described in the enclosed inspection report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observations by the inspectors.

The inspection report identifies several unresolved items regarding the operability of the Auxiliary Salt Water (ASW) system and your management and communication of those issues. The most significant of these unresolved items involved: (1) the basis for the operability of the ASW system with regards to your operational limits on macrofouling, microfouling, and tube plugging; (2) the timeliness of your corrective actions in resolving each of the ASW operability issues identified by your Quality Assurance Department in May 1993 and the effect of each of those issues on ASW operability; and (3) the accuracy and completeness of your response to Generic Letter 89-13 regarding heat exchanger testing results and the existence of a routine ASW piping system inspection program. We are concerned that these unresolved items call into question the basis for long-term operability of the ASW system. We note that subsequent to the end of the inspection you made a 10 CFR 50.72 report on December 30, 1993, which reported past inoperability of the ASW system. However, we remain concerned that the extent of the impact of these issues upon the future operability of the ASW system is not fully understood.

Our concern regarding the adequacy of the ASW system has been previously evidenced by the special analysis requested in 1988 in NRC Inspection Report 50-275/88-11. PG&E responded to those concerns with assurances that the ASW system had adequate margin. Despite these assurances, it is discouraging to now identify that the testing requested by Generic Letter 89-13 resulted in failures that were apparently not thoroughly explored and resolved by your technical and management staff.

We will continue to review these concerns in a future inspection. You are encouraged to perform a detailed evaluation of the past and future operability of the ASW system and promptly evaluate the effects of these unresolved issues. In order to assist in our evaluation of these issues, we request that you inform us of the steps that you will take to resolve these concerns and provide us the results of your technical evaluations in thirty days from the date of this letter.

In accordance with 10 CFR 2.790(a), a copy of this letter, the enclosure, and your response 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,

S. A. Richards, Acting Director,
Division of Reactor Safety
and Projects

Enclosure:
1. Inspection Report Nos. 50-275/93-36 and 50-323/93-36

cc w/enclosures:

Dr. Richard Ferguson, Energy Chair, Sierra Club California
Ms. Nancy Culver, San Luis Obispo Mothers for Peace
Ms. Jacquelyn 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

Report Nos:	50-275/93-36 and 50-323/93-36
Docket Nos:	50-275 and 50-323
License Nos:	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:	Diablo Canyon Site, San Luis Obispo County, California
Inspection Conducted:	December 13 through 17, 1993
Inspectors:	P.P. Narbut, Regional Team Leader
Approved by:	C. A. VanDenburgh Acting Deputy Director Division of Reactor Safety & Projects

1/12/94
Date Signed

Summary:

Inspection from December 13 through 17, 1993 (Report Nos. 50-275/93-36 and 50-323/93-36)

Areas Inspected: 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. Temporary Instruction (TI) 2515/118 and Inspection Procedure 40500 were used as guidance during this inspection.

Safety Issues Management System (SIMS) Items: None

Results:

General Conclusions on Strengths and Weaknesses:

Strengths:

- The QA organization performed a surveillance to determine if the licensee's program and commitments for Generic Letter 89-13 were being properly implemented. The QA effort was performed in technical depth and had significant findings which paralleled the inspection findings. (Paragraph 3)

Weaknesses:

- The engineering organization's technical response to the service water issues raised in Generic Letter 89-13 was not performed in sufficient technical depth to identify significant operability issues which were subsequently raised by the QA organization and this inspection. (Paragraph 2.b.3)

- The engineering organization's response to the service water issues raised by the QA surveillance of May 1993 was not timely. The issues had not been resolved at the time of inspection in December 1993 (Paragraph 3.a)

- The licensee's response to Generic Letter 89-13 regarding heat exchanger testing results and the existence of a routine ASW piping system inspection program apparently contained incomplete information (Paragraphs 2.b.2 and 2.c.1).

Significant Safety Matters: The operability of the CCW heat exchangers was not clearly established by the licensee's 1991 heat exchanger performance testing, nor by the licensee's program for heat exchanger preventative maintenance, trending, inspection, and flow testing. The licensee performed an operability evaluation which stated that it considered the heat exchangers at least temporarily operable due to the low winter ocean temperatures. The licensee further determined that the heat exchangers may not have been operable in the past.

Summary of Violations and Deviations:

None.

DETAILS

1. Persons Contacted

Pacific Gas and Electric Company

*J. D. Townsend, Vice President and Plant Manager, Diablo Canyon Operations
*D. H. Behnke, Senior Engineer, Regulatory Compliance
R. P. Powers, Manager, Nuclear Quality Services
*G. M. Burgess, Director, Systems Engineering
*W. G. Crockett, Manager, Technical and Support Services
S. R. Fridley, Director, Operations
J. R. Hinds, Director, Nuclear Safety Engineering
*K. A. Hubbard, Engineer, Regulatory Compliance
M. E. Leppke, Assistant Manager, Technical Services
*C. M. Seward, Sr. Engineer, Mechanical Maintenance
*J. R. del Mazo, Group Supervisor, Nuclear Engineering Services
*D. G. Howland, Mechanical Engineer, Nuclear Engineering Services
*M. L. Da Re, System Engineer
*D. A. Taggert, Director, Site Quality Assurance
*S. C. Ketelsen, Auditor, Nuclear Quality Services
*D. B. Miklush, Manager Operations Services
*G. W. Gurley, Power Production Engineer
*V. R. Foster, Senior Power Production Engineer
K. S. Smith, Mechanical Engineer, Nuclear Engineering Services
F. L. Steinert, Senior Scientist, Aquatic Systems Inc.
J. E. Anastasio, Power Production Engineer

U. S. Nuclear Regulatory Commission

M. H. Miller, Senior Resident Inspector

*Denotes those attending the exit interview on December 17, 1993.

The inspector interviewed other licensee employees including operators, maintenance personnel, engineers, and quality assurance personnel.

2. Examination of PG&E's Actions for Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

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 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.

Scope of Inspection

The inspection reviewed the licensee's actions described in the two PG&E letters discussed above and reviewed the licensee's implementing procedures for those actions. The inspector conducted a walkdown of the system with the system engineers from the site and from the design offices. The inspector reviewed selected records of licensee tests and inspections including videotape of an inspection of piping internals. The inspector also examined the internals of CCW Heat Exchanger 2-1 when it was opened for cleaning. In addition, after independently making several findings, the inspector was apprised of, and reviewed, a Quality Assurance surveillance which contained many of the same findings.

Overview

The inspector concluded that the licensee had implemented a number of actions in response to the generic letter. Some of the actions had resulted in improved performance. Examples of improved performance included continuous chlorination of the Auxiliary Salt Water (ASW) system which resulted in a greatly decreased frequency of system cleaning due to macrofouling. (Macrofouling refers to piping and heat exchanger fouling due to marine organisms such as mussels and barnacles. Microfouling refers to the growth of algae or other micro-organisms.) Another example of improved performance was the accelerated repair program for rusting reinforcing bar and spalling concrete in the intake structure.

The inspector found that the licensee's heat exchanger test results showed that one 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 cold 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.

In 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 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.

The inspector also found that the licensee had not fulfilled all of the commitments made to the NRC. Specifically, the licensee had not established procedures for a routine inspection for ASW piping.

In general, the inspector concluded that the licensee had not developed a good engineering understanding of the effects microfouling, macrofouling, and heat exchanger differential pressure and had not implemented 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 been previously raised in 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. These multiple missed opportunities indicate ineffective engineering involvement in the issues.

Inspection Details

a. Biofouling Controls

Generic Letter 89-13 recommended an ongoing program of surveillance and control techniques to reduce the incidence of flow blockage problems as a result of biofouling. In letters DCL-90-027, dated January 26, 1990, and DCL-91-286, dated November 25, 1991, the licensee explained that they would visually inspect the ASW intake structure once per refueling outage, that they would install a continuous chlorination system, and that they would continue their existing program for monthly system flow testing.

Intake Inspection - The inspector reviewed the licensee's actions for the intake. The actions were described in a series of computerized, recurring, work order tasks. The inspection requirements for the intake structure appeared to be implemented as described to the NRC.

Chlorination Program - The licensee implemented a continuous chlorination program which appeared to be very effective and eventually resulted in a significant reduction in the frequency of heat exchanger outages for cleaning. However, the inspector noted that during the initial chlorination periods during 1992 the frequency of cleaning was greatly increased due to mussel kills. For several months the heat exchangers were taken out of service every few days for cleaning. During this period, the licensee temporarily allowed the heat exchangers to exceed their operational differential pressure limit of 140 inches, be declared inoperable and left in service until a limit of 200 inches was reached.

System Flow Testing - The licensee continued to perform monthly flow tests of the ASW system using temporary test instrumentation. The ASW system at Diablo Canyon does not have installed flow instrumentation available to the operators. Operators infer adequate flow from the differential pressure across the heat exchanger and from the ASW pump motor currents. The inspector observed that the monthly test was performed in accordance with procedure STP M-26, Revision 11, "ASW System Flow Testing." The test acceptance values did not include a simple value for minimum flow, but provided a series of curves dependent on the ocean and Component Cooling Water temperatures. The licensee stated the acceptance values are from a study done in 1992 by Westinghouse. The study is 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. The study is one of three different design bases described in the licensee's design criteria memorandum, DCM No. S-17B Revision 2.3, "Auxiliary Saltwater System." The licensee stated that the revised design bases had not been reviewed by the NRC technical branches. The acceptability of the licensee's revised design bases is considered an open item. (Followup item 50-275/93-36-01)

b. Heat Exchanger Capacity Test

Generic Letter 89-13 requested that licensees conduct a test program to verify the heat transfer capability of all safety-related heat exchangers. The generic letter allowed for an alternative program such as frequent regular maintenance of the heat exchanger.

In 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. The letter further explained that the licensee would implement an alternative program to verify the system would remain capable of maintaining design basis capability. The letter stated that the licensee would implement a monitoring program which combined flow testing, trending, inspection, and frequent preventative maintenance. The letter stated these actions would be completed by the end of the 1991 fourth refueling outage of each unit.

In 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 letter also stated that the licensee had implemented the alternate monitoring program.

The inspector reviewed the results of the one-time heat exchanger test. The test methods and results are described 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 was not performed by plant personnel but by personnel from the licensee's Technical and Ecological Services Division in San Ramon, California. The inspector had the following observations and findings:

(1) Non Conservative Testing Due to Inadequate Initial Test Conditions

The inspector found that several important initial conditions were not established for the test. The missing initial conditions were:

- An assessment of the amount of microfouling and macrofouling present in the heat exchanger. The lack of this information precludes assessing the acceptability of the microfouling and macrofouling found in the licensee's regular monitoring program. The lack of this information also resulted in the test result projections to design conditions not accounting for the maximum allowed fouling. This approach was not conservative.

- The recording of the amount of differential pressure present in the heat exchanger. The operators use the differential pressure as an assessment of the degree of macrofouling. The failure to record differential pressure precluded the use of the test data as an assessment of the adequacy of the operator's differential pressure limits.

- A measurement of the outlet water box water level. The outlet water box operates at a negative pressure and does not run full at Diablo Canyon. This information is based on an informal test performed by the system engineer in 1988. The water level in the outlet water box apparently varies with the tide according to operators. This additional variable also affects the measurement of differential pressure across the heat exchanger.

(2) Inaccurate and Incomplete Information

The licensee's letter DCL-91-286, dated November 25, 1991, stated that: "...the computer model predicted that the heat exchanger would remove the design basis heat load at design conditions." The inspector's review of Field Test Report 420DC-91.1156 showed that the computer prediction for Unit 1 heat exchanger CCW 1-2 did not show that the heat exchanger would remove the design basis heat load. Rather, the test results showed the heat exchanger capacity to be at 98.7 percent of design. The inspector also determined that the differential pressure across the heat exchanger was probably at only 101-104 inches based on informal records. Therefore, the heat removal capacity would have been less if the licensee had accounted for the maximum allowed differential pressure of 140 inches.

In response to the inspector's finding, and in accordance with their procedures, the licensee initiated a Prompt Operability Assessment (POA) for the heat exchanger test failure. The licensee concluded that the heat exchanger was operable under the existing conditions of cold winter ocean temperatures. The licensee also initiated a more complete long term operability assessment which was to be completed in 7 days.

The apparent failure 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 is considered an unresolved item pending further examination of the circumstances of the omission. (Unresolved item 50-275/93-36-02).

(3) Inadequate Preventative Maintenance Limits

The inspector observed that the heat exchangers were taken out of service for cleaning of macrofouling accumulations when the differential pressure across the heat exchanger approached 140 inches of water. The alarm setpoint for the differential pressure alarm was set at 140 inches and this was used by the operators as the limit for system operability. The inspector examined the basis document for the alarm setpoint to determine the technical basis for the 140 inch limit. The setpoint basis document stated that the setpoint was based on engineering judgement, but did not provide a technical basis for this judgement.

In order to make an independent engineering judgement, the inspector examined CCW Heat Exchanger 2-1 which had been taken out of service at a differential pressure of about 125 inches per the shift foreman. The heat exchanger had been taken out of service in November for cleaning, was getting a high differential pressure much sooner than the other heat exchangers and was expected to have less macrofouling than the other CCW heat exchangers would at the same differential pressure. Heat exchanger CCW 2-1 was more sensitive than the other heat exchangers due to a known buildup of calcification on the outlet end. The key point was that the other heat exchangers would show more macrofouling than CCW 2-1 at a given differential pressure.

In CCW 2-1, the inspector noted that 10 tubes were permanently plugged due to tube wear problems. Fifteen tubes were plugged with mussels and barnacles. Three crabs were in the head which would have represented at least another 3 tubes being blocked in service. Therefore, the inspector estimated a total of 28 blocked tubes. Since heat exchanger CCW 2-1 was taken out of service with only 125 inches of differential pressure, the inspector estimated that the amount of macrofouling and the number of plugged tubes at 140 inches would have been much higher. Also, because CCW 2-1 was running at a higher initial differential pressure after cleaning due to its greater calcification, the amount of macrofouling and plugged tubes in the other heat exchangers (CCW 1-1, CCW 1-2, and CCW 2-2) would be even more severe than the macrofouling in CCW 2-1 for any given differential pressure. Therefore, the inspector concluded that any of the heat exchangers would have significantly more than 28 tubes plugged with a differential pressure of 140 inches.

The licensee stated that their tube plugging limit was 2 percent of the total tubes or 24 plugable tubes total. This limit was provided to the licensee on March 30, 1993, by a facsimile memorandum from Yuba Heat Transfer Division. The memorandum stated that: "There is an inherent factor of safety in the heat transfer formulas such that the heat exchangers should achieve the design heat transfer rate with as many as 2 percent of the tubes plugged."

Based on the above information, the inspector's technical judgement was that the differential pressure limit of 140 inches was excessive and that the heat exchangers may have been inoperable during conditions of warmer ocean temperatures.

In response to the inspector's finding, and in accordance with their procedures, the licensee included this issue in the Prompt Operability Assessment (POA) written for the heat exchanger test failure. The licensee concluded that the heat exchanger was operable under the existing conditions of cold winter ocean temperatures. The licensee also initiated a more complete long-term operability assessment which was to be completed in 7 days. This operability evaluation was completed on December 30, 1993, as discussed in Section 3.d. of this inspection report.

This issue is a significant item due to the high safety significance of the system and the number of opportunities the licensee had to address the issue. System operability concerns due to differential pressure had been raised in Inspection Report 50-275/88-11 and 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 and maintenance practices. The failed heat exchanger capacity test in 1991 should have triggered investigative actions but did not. Finally, a QA surveillance in May 1993 (discussed in Section 3 of this report) raised the specific issue of the adequacy of the differential pressure setpoint, but did not elicit a studied response from the engineering organization. These multiple missed opportunities indicate that engineering was ineffective.

The apparent failure to establish adequate differential pressure limits to ensure CCW heat exchanger operability is an unresolved item pending the licensee's assessment of operability and the inspector's review of that assessment. (Unresolved item 50-275/93-36-03)

c. Inspection and Maintenance of the ASW System Piping

Generic Letter 89-13 recommended that a routine 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 letter DCL-90-027, dated January 26, 1990, the licensee stated that they would develop a program and that procedures to establish a routine inspection and maintenance program for the ASW system would be established by the 1991 fourth refueling outages of Units 1 and 2. In letter DCL-91-286, dated November 25, 1991, the licensee stated that they had established a routine inspection and maintenance program.

(1) Lack of a Piping Inspection Program

The inspector examined a sample of the licensee's program and procedures for the inspection and maintenance of the ASW system. The inspector found that the licensee had not established a routine inspection program or procedures to inspect the ASW piping.

During the Unit 1 fourth refueling outage in March of 1991, the licensee inspected 1790 feet (about 50 percent) of the Unit 1 piping using a temporary procedure which utilized a television camera. Unit 2 was inspected in a similar manner in October 1991. Both inspections did not reveal significant problems, although two small areas of damaged coating and localized corrosion were observed. The two areas required weld repair to restore minimum wall. However, subsequent to the initial inspection the licensee did not establish a program defining the amount or period of any additional inspections to be conducted. No additional inspections were done in the fifth refueling outages of Units 1 or 2. Responsible engineers stated that there were no plans for an inspection during the sixth refueling outages in 1994. The licensee had an 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 period be established. However, those actions had not been completed.

The apparent failure to develop a routine inspection program for the ASW system piping by the end of the 1991 fourth refueling outages of Units 1 and 2, as committed to in letter DCL-90-027 dated January 26, 1990, and the apparent failure to provide accurate implementation status of the piping inspection program in letter DCL-91-286, dated November 25, 1991, are considered unresolved pending further inspection of the circumstances involved. (Unresolved item 50-275/93-36-04)

d. Confirmation of the Licensing Basis of the ASW System

Generic Letter 89-13 requested that licensees confirm that the service water system can perform its intended function in accordance with the licensing basis for the plant. In letters DCL-90-027 dated January 26, 1990, and DCL-91-286, dated November 25, 1991, the licensee explained that they had completed the development of Design Criteria Memorandums (DCMs) in 1990 and that no significant design deficiencies were identified confirming that the ASW system would perform its intended function in accordance with the licensing basis.

Although the inspector did not examine the licensee's actions for confirming that the ASW system would perform its intended design function, the inspection results discussed in Section 2.b. of this report regarding a lack of engineering understanding of the validity of the operational controls for microfouling, macrofouling, and heat exchanger differential pressure suggest that the licensee's actions were not sufficient. Likewise, there were significant technical findings in the licensee's QA surveillance of the licensee's commitments for Generic Letter 89-13 discussed in Section 3 of this report. The QA findings suggest that engineering controls on operational configurations were not sufficient to preclude pump runout conditions in certain situations.

The licensee's DCM for the ASW system, DCM No.S-17B, addresses some of these issues but only in a general manner such as "...useful heat transfer area is dependent upon heat exchanger maintenance. Assuming the CCW heat exchanger is maintained per standard practices the selection of a conservative fouling factor can be made." and "This heat exchanger high differential alarm is provided as a diagnostic tool which operations/maintenance personnel use to determine when cleaning is required to assure that significant fouling and/or blockage of the heat exchanger does not occur." As stated in Section 2.b, the only basis for the alarm setpoint in the licensee's setpoint basis document is described as judgement.

In addition, the issue of the adequacy of the 140 inch differential pressure limit was specifically questioned in NRC Inspection Report 50-275/88-11. The licensee responded to the issue in letter DCL-88-215, dated September 13, 1988. This response was also general in nature and stated, "...a heat exchanger high differential alarm was provided as a diagnostic tool which operations/maintenance personnel use to determine when cleaning is required to assure that significant fouling and/or blockage of the heat exchanger does not occur."

The inspector concluded that the licensee's review of their design basis to verify that the ASW system would perform its intended design function did not identify several important design basis issues. An assessment of the need to reperform an assessment of the adequacy of their design basis for the ASW system is a followup item. (Followup item 50-275/93-36-05)

d. Licensee Operability Evaluations

On December 30, 1993, the licensee made a 10 CFR 50.72 report to the NRC which concluded that on August 23, 1990, and perhaps dates prior to and subsequent to that date, the CCW heat exchangers for both units may have had sufficient fouling to have precluded the systems from meeting their design bases. Also on December 30, 1993, the licensee performed, and the Plant Safety Review Committee (PSRC) approved, an operability evaluation and concluded that the ASW system was operable since the initiation of the continuous chlorination program in October 1992.

3. Review of QA Involvement

The inspector reviewed the licensee's QA surveillance report SQA-93-0031, dated July 28, 1993. The licensee conducted the audit from March 5 to May 7, 1993. The report raised many of the same issues as were raised by the inspector and other issues not identified by the inspector. The inspector noted that the surveillance was an in depth examination of not only the commitments made to the NRC, but also the underlying technical bases involved with the commitments. The inspector further noted that the QA personnel had not only raised the issues but also critically reviewed the responses of engineering and rejected the answers when appropriate. Although the issues were formally identified to engineering in May of 1993 by action requests, the issues had not been resolved at the time of the inspection.

Examples of issues identified by the inspector and QA report included:

- The failure of CCW Heat Exchanger 1-2 to pass its performance test. The QA report requested engineering to provide a written evaluation of the results in Action Request (AR) A0306715. The engineering response to the AR was not accepted by QA and a reevaluation was requested on August 12, 1993. Engineering had not responded to the request for a revaluation at the time of the inspection.

- The concern with the 140 inch differential pressure setpoint for the CCW heat exchangers. Likewise, the issue had not been resolved at the time of the inspection.

Additional excellent technical issues were identified by the QA report. Examples of these issues included:

- A concern regarding the fact that test results showed that the ASW system flow was reduced by much more than was concluded by licensee calculations for the condition where system flow was aligned through the pump cross-tie. This problem was identified in AR A0309356 dated June 11, 1993.

- A concern regarding the lack of operational limits for protecting the system from high flow rates under 1 pump and 2 heat exchanger configurations.

The inspector considered the number, importance, and technical depth of the QA surveillance findings to be a licensee strength. The QA evaluation and rejection of poor engineering responses to the QA findings was also considered a strength. The failure to resolve the QA findings in a timely manner was considered a weakness.

a. Failure to take Timely Action

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 identified again during a

QA surveillance and documented on Action Request No. A03066715 dated May 10, 1993. As of the end of the inspection on December 17, 1993, the effect of the test failure on ASW system operability had not been resolved.

The apparent failure to promptly resolve conditions adverse to quality is considered an unresolved item pending further review of the circumstances involved. (Unresolved item 50-275/93-36-06)

4. Other Observations

a. Use of a Computer Code that had not been Validated

When reviewing the CCW heat exchanger capacity tests previously discussed, the inspector noted that the test report, Field Test Report 420DC-91.1156, "Diablo Canyon Power Plant CCW Heat Exchanger Performance Tests Units 1 and 2," performed by the licensee's Technical and Ecological Services Division, described the use of a computer code to project design basis heat transfer capacity. The computer code was described as not having been validated for accuracy. The failure to use a validated computer code is considered an unresolved item pending further review of the details involved. (Unresolved item 50-275/93-36-07)

b. Calcification of Heat Exchanger Tubes

The inspector learned that calcification had been observed on the inner diameter of the CCW heat exchanger tubes. The calcification was located only at the outlet end of the heat exchanger in the tube sheet area. The system engineer stated that the cause of the calcification was deposits from seawater caused by the impressed voltage system for cathodic protection of the ASW piping. The system engineer further stated that the calcification was of a short length and would not affect the available heat transfer area or tube fouling factor. The inspector expressed the concern that since the buildup was not being trended for rate of buildup, and since the inlet of the tubes had a reduced diameter, the calcification 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 effect of the calcification on the heat exchanger capacity and the potential effect of undetected tube plugging is a followup item. (Followup item 50-275/93-36-08)

c. Trending not Performed

The inspector inquired as to whether the system engineer was trending the amount of macrofouling found in each CCW heat exchanger and the consequent amount of tube plugging. The system engineer stated that macrofouling was trended by the biologists. However, the biologists only trended amount and species but did not count tubes plugged. Further discussion with the system engineer disclosed that system availability was no longer trended. System availability had been previously trended and the information had been used to update the licensee's Probabilistic Risk Assessment (PRA).

Although there is no regulatory requirement to trend system performance, the inspector's observation was provided to licensee management at the exit interview for information.

d. Lack of ASW Flow Instruments for Operator Information

The inspector noted that the operators do not have ASW flow information available in the control room. A flow instrument installed at the intake structure does not indicate accurately according to the system engineer. The operators infer flow from the differential pressure across the heat exchanger and by observing the electrical current to the ASW pump motors. Although, there is no regulatory requirement for flow instrumentation, this matter was discussed with the licensee at the exit interview.

5. Exit Meeting

An exit meeting was conducted on December 17, 1993, with the licensee representatives identified in Paragraph 1. The inspector summarized the scope and findings of the inspection as described in this report.

The licensee did not identify as proprietary any of the materials reviewed by or discussed with the inspectors during this inspection.

5073

— Attachment 2

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

CONTACT: C. Vernon Hodge, NRR
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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 Re u-latory 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

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.

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.

JUN 17 1988

Docket Nos. 50-275 and 50-323

Pacific Gas and Electric Company
77 Beale Street, Room 1451
San Francisco, California 94106

Attention: Mr. J. D. Shiffer, Vice President
Nuclear Power Generation

Gentlemen:

Subject: NRC Inspection of Diablo Canyon Units 1 and 2

This refers to the routine inspection conducted by Messrs. P. P. Narbut, L. M. Padovan, and K. E. Johnston during the period of April 10, through May 28, 1988. This inspection examined your activities as authorized by NRC License Nos. DPR-80 and DPR-82. Additionally, the areas of System Engineering and Root Cause Analysis were examined by Mr. D. F. Kirsch and Mr. J. L. Crews, respectively. At the conclusion of the inspection, discussions of our findings were held with Mr. J. D. Townsend, and other members of your staff.

The report also includes the results of two additional inspection efforts: Mr. J. C. Pulsipher's examination of the Integrated Leak Rate Test of the Unit 1 containment during the period of May 16 through 20, 1988; and Mr. B. Collins (of EG&G an NRC contractor) examination of Instrumentation and Controls during the periods of March 28 through April 8 and May 3 through May 19, 1988. Their exit interviews were held on May 19 and May 20, 1988, respectively.

Areas examined during this inspection are described in the enclosed inspection report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observations by the inspectors.

Based on the results of this inspection, it appears that certain of your activities were not conducted in full compliance with NRC requirements, as set forth in the Notice of Violation, enclosed herewith as Appendix A. Your response to this notice is to be submitted in accordance with the provisions of 10 CFR 2.201, as stated in Appendix A, Notice of Violation.

Further, the unresolved item discussed in Section 13.c of the enclosed report, concerning operability of the Auxiliary Saltwater/Component Cooling Water systems, may indicate a need for increased management attention in the area of design/configuration control. As previously discussed and agreed to in our April 22, 1988 management meeting, design/configuration control is clearly an important part of your Diablo Canyon operational activities. Therefore, we request that you provide a discussion of your corrective action program to preclude further instances of potentially unacceptable changes to the operating plant configuration or parameters due to inadequate review or knowledge of the plant systems design bases. Additionally, we request that you include your assessment of the operability of the Auxiliary Saltwater/Component Cooling Water systems in response to the findings in the previously mentioned unresolved item.

In accordance with 10 CFR 2.790 (a), a copy of this letter and the enclosures will be placed in the NRC Public Document Room.

The responses directed by this letter are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, PL 96-511.

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

Sincerely,

original signed

R. P. Zimmerman, Chief
Reactor Projects Branch

Enclosures: Appendix A, Notice of Violation
Inspection Report Nos. 50-275/88-11 and 50-323/88-10
Enclosure 1, EG&G Idaho Report "I&C Maintenance Evaluation of the Diablo Canyon Power Plant"

cc w/enclosures:
S. D. Skidmore, PG&E
R. F. Locke, PG&E
J. D. Townsend, PG&E (Diablo Canyon)
D. A. Taggert, PG&E (Diablo Canyon)
R. S. Weinberg, PG&E (Diablo Canyon)
T. L. Grebel, PG&E (Diablo Canyon)
State of California
Sandra Silver (Report Only)

bcc w/enclosures:
Project Inspector
Resident Inspector
docket file
G. Cook, RV
B. Faulkenberry, RV
J. Martin, RV
A. Johnson, RV
T. Foley, NRR

bcc w/o report:
J. Zollicoffer
M. Smith

RPZ REGION V/dot LMPadovan 6/17/88	RPZ KEJohnston 6/17/88	RPZ PPNarbut 6/17/88	RPZ MMMendonca 6/17/88	RPZimmerman 6/17/88
REQUEST COPY YES / NO	REQUEST COPY YES / NO	REQUEST COPY YES / NO	REQUEST COPY YES / NO	REQUEST COPY YES / NO
				SEND TO PDR YES / NO

MBlume
6/17/88

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YES / NO

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NOTICE OF VIOLATION

Pacific Gas and Electric Company
Diablo Canyon Nuclear Power Plant

Docket Nos. 50-275 and 50-323
License Nos. DPR-80 and DRP-82

During an NRC inspection conducted on April 10 through May 28, 1988 violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1987), the violations are listed below:

A. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action" provides, in part, that licensees shall establish measures "to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, 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, subsequent to the identification of nonconformances leading to a violation (issued in inspection report 50-275/88-07) for lack of required cleanliness controls on March 21 and April 6, 1988, corrective actions taken did not preclude repetition. Specifically, additional incidents of loss of cleanliness controls were identified on April 9, 12, 21, 22, and May 10, 1988, by NRC and licensee personnel, including the discovery on April 22, 1988 of foreign material on the Unit 1 reactor vessel upper internals.

   This is a Severity Level IV Violation (Supplement 1) applicable to Unit 1.

B. Facility Technical Specification 6.8.1 states that: "Written procedures shall be established, implemented and maintained covering...applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978..." Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, Section 9, "Procedures for Performing Maintenance", states that "Maintenance that can affect the performance of safety related equipment should be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances"

   Maintenance Procedure MP M-54.4, "Spiral Wound Gasket Replacement Guide", Revision 7, dated February 16, 1988, provides guidance on the proper replacement of spiral wound gaskets to ensure leak free assemblies. MP M-54.4 includes data sheets required to be completed by the mechanics. In addition, the procedure in paragraph 7.2.2.d.1 requires the use of Felpro N-5000 lubricant on all mating surfaces of nuts and bolts.

   Contrary to the above, on April 27, 1988, while replacing spiral wound gaskets, on a Unit 1 safety injection relief valve header flange, mechanics used an unauthorized lubricant instead of the prescribed Felpro N-5000 and did not complete the data sheets prescribed by MP M-54.4.

This is a Severity Level IV violation (Supplement I) applicable to Unit 1.

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, DC 20555 with a copy to the Regional Administrator, Region V, and a copy to the NRC Resident Inspector, Diablo Canyon, within 30 days of the date of the letter transmitting this 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 if admitted, (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 he time specified in this Notice, an order may be issued to show cause why the license should not be modified, suspended, or revoked or why such other actions as may be proper should not be taken. Consideration may be given to extending the response time for good cause shown.

FOR THE NUCLEAR REGULATORY COMMISSION

R P Zimmerman

R. P. Zimmerman, Chief
Reactor Projects Branch

Dated at Walnut Creek, California
this 17th day of June 1988

U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/88-11 and 50-323/88-10

Docket Nos: 50-275 and 50-323

License Nos: DPR-80 and DPR-82

Licensee: Pacific Gas and Electric Company
77 Beale Street, Room 1451
San Francisco, California 94106

Facility Name: Diablo Canyon Units 1 and 2

Inspection at: Diablo Canyon Site, San Luis Obispo County, California

Inspection Conducted:

Inspectors: M. M. Mendonca for — 6/16/88
L. M. Padovan, Resident Inspector — Date Signed

M. M. Mendonca for — 6/16/88
K. E. Johnston, Resident Inspector — Date Signed

M. M. Mendonca for — 6/16/88
P. P. Narbut, Senior Resident Inspector — Date Signed

M. M. Mendonca for — 6/16/88
J. C. Pulsipher, NRR — Date Signed

Approved by: M. M. Mendonca — 6/16/88
M. M. Mendonca, Chief, Reactor Projects Section 1 — Date Signed

Summary:

Inspection from April 10 through May 28, 1988 (Report Nos. 50-275/88-11 and 50-323/88-10)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, follow-up of onsite events, open items, and licensee event reports (LERs), as well as selected independent inspection activities. Inspection Procedures 25026, 30702, 30703, 37700, 57050, 57080, 60710, 61726, 62703, 70307, 70313, 71707, 71709, 71710, 71881, 73756, 90712,,92700, 92701, 92702, 93702, and 94703 were applied during this inspection.

Results of Inspection:

Two violations were identified. The first dealt with ineffective corrective action in dealing with the loss of system cleanliness controls as described in paragraph 13. d. The second violation dealt with mechanics failing to follow procedures during maintenance activities as described in paragraph 5.a.

An unresolved item is described in paragraph 13.c. dealing with the operability of the Auxiliary Saltwater (ASW) system during the period of time that the heat exchanger differential pressure setpoint was raised.

An apparent weakness is implied by the situation of uncertain operability of the ASW system in that it can be concluded that system design bases have not been successfully communicated to plant personnel and that the result of this may have led to, or could lead to, plant personnel making system setpoint changes which they do not recognize as affecting system operability.

An additional inspector concern raised during this reporting period is the perceived lack of timely, effective corrective actions in dealing with situations in which plant personnel made errors. The two examples discussed in the report are the subject of violations; specifically repeated cleanliness problems and the failure of mechanics to follow procedures. In both cases the job at hand was corrected but plant management appeared content to allow the normal processes resolve the root cause of the problems. The normal process involves a nonconformance report and a technical review group meeting, a process that can and does take months. The action that appears to be missing is an immediate response to ensure other personnel involved in similar work are quickly alerted to the errors made.

During the reporting period there were good examples of individual plant personnel who exercised an inquisitive safety minded approach to their work. Specific examples were the identification of misaligned detectors in the main steam line radiation detectors by an I&C technician, the identification of improper surveillance schedules for time response testing of vital instrumentation channels by an I&C technician, and identification of the possibly generic problem with containment ventilation butterfly valves identified by engineers involved in the integrated leak rate test.

Additionally, the licensee's actions leading to the discovery of possible generic problems with Westinghouse ARD relays was noted as an example of thorough root cause analysis.

DETAILS

1. Persons Contacted

*J. D. Townsend, Plant Manager
*D. B. Miklush, Acting Assistant Plant Manager, Plant Superintendent
J. M. Gisclon, Acting Assistant Plant Manager for Support Services
*C. L. Eldridge, Quality Control Manager
K. C. Doss, Onsite Safety Review Group
R. G. Todaro, Security Supervisor
*T. Bennett, Acting Maintenance Manager
D. A. Taggert, Director Quality Support
*T. J. Martin, Training Manager
W. G. Crockett, Instrumentation and Control Maintenance Manager
J. V. Boots, Chemistry and Radiation Protection Manager
L. F. Womack, Operations Manager
*T. L. Grebel, Regulatory Compliance Supervisor
*S. R. Fridley, Senior Operations Supervisor
R. S. Weinberg, News Service Representative
W. T. Rapp, Chairman, Onsite Safety Review Group
M. Tressler, Project Engineer, NECS

The inspectors interviewed several other licensee employees including shift foreman (SFM), reactor and auxiliary operators, maintenance personnel, plant technicians and engineers, quality assurance personnel and general construction/startup personnel.

* Denotes those attending the exit interview on May 27, 1988.

2. Operational Status of Diablo Canyon Units 1 and 2

During the reporting period Unit 1 continued its second refueling outage. Notable occurrences included the discovery of fatigue cracking in reactor coolant pump lubrication system components, some evidence of pressurizer surge line movement, possible generic problems with Westinghouse ARD relays, biological growth in diesel fuel oil day tanks, combustible fire barrier material, and indications from the ILRT that 48" butterfly valves used for containment purge and exhaust may have directionally dependent leak characteristics.

Unit 2 remaining at power for the reporting period.

3. Operational Safety Verification (71707)

a. General

During the inspection period, the inspectors observed and examined activities to verify the operational safety of the licensee's facility. The observations and examinations of those activities were conducted on a daily, weekly or monthly basis.

NPAP C-16/NPG-7.4, Human Performance Evalution System, Revision 0, dated March 3, 1986

NPAP C-18/NPG-7.5, Events Investigations, Revision 0, dated July 14, 1987

NPAP C-23/NPG-7.6, Technical Review Groups, Revision 0, dated March 10, 1988

A review of the above procedures, related plant records, and discussions with responsible plant managers and supervisors resulted in the following observations and findings:

The licensee has implemented a very effective Human Performance Evaluation System (HPES) program, having been an active participant in this INPO program from the time of its initiation some two years ago. This program is intended to focus on human factor elements of plant events, and is aimed at surfacing for evaluation human factors concerns at a low threshold, e.g., "near misses". The program has an outreach aspect, wherein employees at the plant are encouraged by direct mailings, posters (with associated forms to submit written concerns), etc. in several locations within the plant and corporate offices. During the year 1987, a total of 39 HPES root cause evaluations were performed relating to various operational/maintenance events. Approximately 25 of these were in support of the dispositioning of Nonconformance Reports (NCRs).

The licensees procedures require formal root cause determination for all NCRs, of which there were approximately 135 during the year 1987. When an additional approximately 15 HPES evaluations for root cause determination are added to the number of NCRs, a total of approximately 150 events were subjected to formal root cause determination in the year 1987.

In discussions with the NRC inspector, the Plant Manager expressed his view that the threshold for formal root cause determination should be lowered to include a larger population of events beyond those for which an NCR would be initiated in accordance with current administrative procedures. (See Exit and Management Meetings section of this report for licensee management commitments in this regard).

c. Design Verification and Configuration Control: The Auxiliary Saltwater System (5-37700-1, 37700-2)

The inspector reviewed the Auxiliary Saltwater (ASW) system with respect to its design basis and how that design is implemented in the operating plant. The inspector identified the following weaknesses:

- The design basis assumptions for the ASW system have not been fully implemented into plant procedures and alarm setpoints.

As a result, plant operations have been conducted outside design basis assumptions requiring a review of the ASW system's past operability.

- o The licensee did not have an adequate program for design setpoint control. As a result, the annunciator setpoint for the differential pressure (dP) high alarm across the tube side of the Component Cooling Water (CCW) heat exchanger (Hx) was raised without the appropriate design basis review.

These findings are mitigated by the licensee's current efforts in Configuration Management. Although at the time of this report the licensee's program was in its development stages, the program, as described by the licensee, would establish how design requirements and assumptions are to be implemented through plant operations, maintenance, and surveillance. In addition, it would establish procedural guidance for setpoint control.

System Description and Design Basis

The ASW system is the ultimate heat sink, designed to cool safety related loads during normal operations and following a design basis accident. The system consists of two pumps headered at their discharge located at the intake structure. They pump ocean water through two trains of 24" piping, up 85 feet over a distance of approximately 1600 feet and through the tubes of the CCW Hxs. At the discharge of the Hxs the ASW is discharged at 68 feet above sea level and cascades to the ocean. The tube side of the CCW Hx has a differential pressure transmitter with a high and low annunciation in the control room.

The inspector reviewed and discussed the ASW design with the system design engineers at the licensee's office in San Francisco. The licensee could not provide the original design calculation. Much of the original design took place in the late '60s and early '70s when complete records were not kept. The system was assembled around 1973 and tested in 1974 and 1975. In 1982, during the design verification program (DVP), the licensee performed calculations based on as-built conditions to verify the ASW system could meet its design basis.

The limiting parameter for the ASW system was determined to be CCW temperature following a design basis Loss of Coolant Accident (LOCA). The limiting component was determined to be the centrifugal charging pump lube oil coolers which was rated at up to 132 degrees F for 20 minutes. It was determined that containment could be kept below allowed temperature and pressure limits during a LOCA with two of five containment fan cooler units (CFCUs).

Licensee calculations M-305 Revision 3 assumes the following:

- o An initial ASW temperature of 64 degrees F. Above 64 degrees F ocean temperature, the Technical Specifications require the use of both Hx.

- A pre-LOCA CCW temperature of 80 degrees F. This is based on the maximum normal CCW loads.

- The use of five CFCUs. All five CFCUs start on a Safety Injection System signal. Operator action would be required to shut down a CFCU at it's breaker.

- ASW flow of 10,700 gpm which is based on flow taken from the manufacturers pump curve assuming "mean low-low water" level of -2.6 feet mean sea level (MSL) and the Hx tube outlet at atmospheric pressure.

- A fouling factor, used in the heat transfer coefficient of 0.001.

The results concluded that given these conditions, one train of ASW can remove the post-LOCA heat added to the CCW system without having the CCW outlet exceeding 132^{o} F. The licensee did not take credit for any operator action.

Design Basis vs Plant Configuration and Procedures

The inspector reviewed plant configuration and procedures against the above design basis assumptions. The following is a summary of the discrepancies found:

- The Hx dP HI alarm setpoint was 167" water whereas a clean Hx dP of 75" water was assumed in the design calculations. The following section discusses this finding in more detail.

- The Inlet bay low level alarm was set at -10' MSL whereas a level of -2.6' was assumed in the design calculations. The effect of a lower inlet bay level would be to lower suction head and consequently discharge head resulting in less flow.

- ASME Code Section XI allows pump performance to drop to 10% of its reference whereas the design calculations took pump performance from the pump curve without allowing for degradation.

- The CCW Hx shell side outlet temperature high alarm setpoint was set at 120 degrees whereas the highest normal operating temperature was assumed to be 80 degrees. If during normal operations CCW temperature rose above 80 degrees, the unit would be operating outside design assumptions.

- Plant Procedures address actions to be taken if both ASW pumps fail (cross-tie with other unit) and if CCW pumps fail (reduce system heat loads such that CCW temperature is less than 95 degrees) but not actions to be taken if one ASW train does not provide sufficient cooling.

- o Plant procedures did not specifically state that operators could remove from service CFCUs during a LOCA to remove heat loads from the CCW system.

- o Annunciator Response Procedure PK-0101 in step 7a. allows operators to throttle the CCW Hx tube side outlet valve if ASW pump dP is less tha. the Section XI limit. The procedure did not have operations notify engineering to evaluate the operability of the pump.

The first three findings listed raised questions of the ASW system's ability to perform its function under conditions less conservative than assumed in its design basis calculations.

The inspector discussed these findings with the Project Engineer for Diablo Canyon who committed to provide a written analysis of ASW system operability to the NRC by June 7, 1988. Pending a review of the analysis this item is Unresolved (Open Item 50-275/88-11-02).

These findings also show that many design assumptions were not incorporated into plant operations. As corrective action for the ASW system, the licensee plans to establish what design assumptions need to be implemented and revise procedures, alarm setpoints, instrumentation and documentation as necessary. To address these concerns on a larger scale, the licensee had initiated a Configuration Management program in November 1987. As described by the licensee, this program would address the issue of design basis implementation in plant operations. Although the significance of these findings as related to general design basis understanding and implementation is mitigated by the Configuration Management Program, continued attention needs to be focused on this issue.

Setpoint Control

The inspector investigated the basis for the annunciator setpoint for dP across the CCW Hx tubes, pressure switches PS 45 and 46. It was determined that the setpoint of 167" of water had been established in March 1987 following a design change to install pressure transmitters and switches with a higher range. The design change had been initiated in 1985 by the operations department since Hx fouling dP across the Hxs was routinely above the existing setpoint of 110" during normal operations. The engineering reviewers of the design change erroneously determined that the change did not affect equipment important to safety or equipment important to environmental quality. In the general notes contained in the design change package Project Engineering authorized Operations to revise the setpoints for PS 45 and 46 but did not give them specific guidance except to state that Operations should follow up by revising drawing 101938 (Non-Safety Instrument Setpoints) with a field change.

Operations revised the setpoint from 110" to 167" basing the revision on a calculation of only one limiting condition; the maximum flow velocity through the tubes. The flow velocity according to the vendor should be kept below 7 feet per second; 167" correlates to 6.6 fps.

Upon subsequent investigation, the inspector found that safety related Drawing Nos. 060836 (for Unit 1) and 061236 (for Unit 2), "Instrument Setpoint Requirements" Table II lists the high alarm setpoint for PS 45 and 46 to be 4 psid which corresponds to 110.7". The cover note to the drawing states "Table II of this drawing lists other non-instrument Class 1A setpoints which engineering has determined to be appropriate to meet various FSAR commitments." This design drawing was not reviewed or changed when the setpoints of PS 45 and 46 where changed. This is a failure of Engineering not to reevaluate the basis for the original setpoint and is an apparent violation of Criterion III, "Design Control," of 10 CFR 50 Appendix B but will be treated as unresolved until the significance of the ASW/CCW systems operating with a 167" differential pressure setpoint is resolved. Following the meeting of the Technical Review Group for the ASW system Non Conformance Report, Operations put an administrative limit on CCW Hx tube side dP of 110" pending the resolution of the basis for the 110" setpoint. Subsequently, it was determined that the dP setpoints in Drawing Nos. 060836 and 061236 to control the low alarm setpoint satisfied the FSAR commitment for a control room alarm on ASW piping failure. Regardless, system performance is directly effected by Hx fouling and requires setpoint control. The licensee was in the final stages of a comprehensive revision to the setpoint control program at the time of this finding. These revisions appear adequate to ensure that important setpoints are reviewed against the design basis.

d. Cleanliness Control Problems (5-92700-4)

In previous resident inspector report (Inspection Report 50-275/88-07), two cleanliness problems were identified during the performance of refueling outage work. The two areas examined previously were the removal of thermocouple connoseals on March 21 and spare control rod drive mechanism work on the removal of the reactor vessel head on April 6, 1988.

During this reporting period the control of cleanliness problems continued. On April 9, 1988, quality control (QC) personnel issued a stop work on CRDM cleanliness requirements. The stop work was lifted later that day after corrective action was taken. The action consisted of erecting barriers around the refueling cavity that were shown later to be ineffective. Additionally a memo was issued by engineering to the engineering task coordinators regarding cleanliness controls. Subsequent events showed that this memorandum was ineffective in precluding further occurrences.

On April 12, 1988, QC inspectors identified that cutting fluid and chips were being allowed to enter crevice areas on the reactor vessel head. Accordingly, a stop work was issued. Subsequently, the licensee implemented corrective actions. These corrective actions consisted of cleaning the crevices and revising the procedure for cutting to include a QC holdpoint to verify barriers were installed. Corrective actions did not include personnel reinstruction even though the procedure used had a specific caution note requiring steps be taken to preclude fluids from entering the crevices.

On April 22, 1988, during the attempt to reinstall the upper internals, work was stopped by the refueling crew due to the sighting of debris on the upper internals which was initially reported as tools (pliers, nuts, and washers). The debris was retrieved and determined to be a broken "tie wrap" (a plastic strap ordinarily used to secure electrical cable to cable trays) and paint chips.

The inspector attended the licensee's corrective action meeting on April 22, 1988. The inspector entered containment with the engineer assigned the responsibility to determine the probable source of the debris on the upper internals.

The engineers in charge of the job did not "save the evidence" upon debris retrieval, but rather had it placed in radioactive waste. It was retrieved by the licensee and the inspector observed that the tie wrap looked old (yellowing in color as opposed to new white) and the paint chips were yellow paint. The conclusion drawn was that the tie wrap probably came from the reactor vessel head and its cable trays. The inspector then examined the work area on top of the reactor vessel head and noted several unsatisfactory conditions. The removed head was stored immediately adjacent to the refueling cavity; most of the components on the head do not hang over the cavity, but a portion of the cable tray area does hang over the pool. The tie wrap found on the internals was directly under the head area cable tray. The inspector found additional broken tie wraps in the cable tray area which had the potential to fall.

Additionally, on the upper area of the head (where work had been underway to remove and replace digital rod position indicator (DRPI) stacks for CRDM weld repair access) the inspector found a great deal of dirt (up to 1/4" thick) including broken microphone ceramics abandoned in place since pre-operational testing. The engineer in charge of that work explained that prior to removing any DRPI coils, the local area around the DRPI coil was vacuumed, and that any dirt dislodged would fall straight down and not into the refueling cavity. However, he further explained that one of the interlocking steel plates in that same area had been inadvertently kicked, fell, bounced off a structure, and ended up in the refueling cavity pool, and was yet to be retrieved. Therefore, the logic that dirt and debris would only fall straight down appeared to be faulted.

The inspector discussed the cleanliness situation with the engineers in containment and with the outage manager that evening. All areas were recleaned and verified clean prior to recommencing reactor assembly.

Pacific Gas and Electric Company

January 26, 1990

PG&E Letter No. DCL-90-027

Attachment 4

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 J. D. Shiffer
J. D. Shiffer
Vice President
Nuclear Power Generation

Howard V. Golub
Richard F. Locke
Attorneys for Pacific
Gas and Electric Company

By Richard F. Locke
Richard F. Locke

Subscribed and sworn to before me
this 26th day of January 1990

Mildred J. Williams
Mildred J Williams, Notary Public
for the City and County of San Francisco
State of California

My commission expires August 7, 1993.

MILDRED J. WILLIAMS
NOTARY PUBLIC - CALIFORNIA
CITY & COUNTY OF SAN FRANCISCO
My Commission Expires Aug. 7, 1993

cc: A. P. Hodgdon
J. B. Martin
M. M. Mendonca
P. P. Narbut
H. Rood
CPUC
Diablo Distribution

Enclosure

3037S/0077K/ALN/2232

A065

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. Howrver, 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 circ ılating 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 ASW 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 STP 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.

Attachment 5

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,

Greg Rueger

Gregory M. Rueger

cc: Ann P. Hodgdon
John B. Martin
Philip J. Morrill
Harry Rood
Howard J. Wong
CPUC
Diablo Distribution

Enclosure

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ENCLOSURE

SUPPLEMENTAL RESPONSE TO GENERIC LETTER 89-13, "SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT"

5551S/85K

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 mo. 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 pra ices, 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.