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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

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**BEFORE THE ATOMIC SAFETY AND LICENSING BOARD**

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| In the matter of<br>Pacific Gas and Electric Company | ) Docket Nos. 50-275-OLA<br>) 50-323-OLA-2 |
| | ) |
| Diablo Canyon Nuclear Power Plant | ) Construction Period<br>) Recovery |
| Units 1 and 2 | ) |
| | ) November 19, 1993 |

**San Luis Obispo Mothers for Peace**
**Proposed Findings of Fact and Conclusions of Law**
**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**

Diane Curran

Harmon, Curran, Gallagher & Spielberg
c/o IEER
6935 Laurel Avenue Suite 310
Takoma Park, MD 20912
(301) 270-5518

Jill ZamEk

San Luis Obispo Mothers for Peace
P.O. Box 164
Pismo Beach, CA 93448
(805) 773-386



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## Introduction

1- This decision rules on contested issues raised by Intervenor San Luis Obispo Mothers for Peace (hereinafter "MFP" or "SLOMFP") regarding Pacific Gas & Electric Co.'s ("PG&E's") application to the Nuclear Regulatory Commission ("NRC" or "Commission") to extend the term of its operating licenses for the Diablo Canyon Nuclear Power Plant ("DCNPP") by more than 13 years for Unit 1 and almost 15 years for Unit 2. The requested license amendment would allow PG&E to "recapture" the period in which the plant was being constructed, and extend the term of its operating license to a full 40 years from the date of issuance.

2- For the reasons discussed below, the Licensing Board finds that PG&E has not demonstrated that it can operate during the license extension period with a reasonable assurance of safety. In particular, PG&E has not met its burden of demonstrating that it has and will have an adequate maintenance and surveillance program; or that has taken or will take effective measures to compensate for Thermo-Lag passive fire barriers. Accordingly, PG&E's application for a license extension is denied.

**Background**

3- When DCNPP received its operating license, its 40-year term was measured from the date that DCNPP received its construction permits for Unit 1 and Unit 2. Thus, PG&E's operating licenses are set to expire in 2008 for Unit 1 and 2010 for Unit 2. 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.

4- SLOMFP timely petitioned to intervene and requested a hearing on the proposed license amendment. The Board found that the group had standing and admitted two contentions, which challenged the adequacy of PG&E's maintenance program, and the adequacy of PG&E's interim fire protection measures to compensate for defective passive fire barriers manufactured by Thermo-Lag. Pacific Gas & Electric Co. (Diablo Canyon Nuclear Power Plant, Units 1 and 2), LBP-93-1, 37 NRC 5 (1993).

5- Between August 17 and August 24, 1993, the Licensing Board held a hearing on the issues raised by SLOMFP. PG&E and the NRC submitted testimony on the issues. SLOMFP put on no witnesses, but submitted numerous PG&E and NRC documents regarding the issues raised in their contentions.

6- The Board addresses the contested issues below. The decision is divided into two parts, the first part addressing Contention I (Maintenance and Surveillance) and the second part addressing Contention V (Thermo-Lag Compensatory Measures).

<u>PART 1</u>

<u>CONTENTION I: MAINTENANCE AND SURVEILLANCE</u>

<u>Background</u>

7- MFP's Contention I asserts that:

> Pacific Gas & Electric Company's proposal to extend the life of the Diablo Canyon Nuclear Power Plant for more than 13 years (Unit 1) and almost 15 years (Unit 2) should be denied because PG&E lacks a sufficiently effective and comprehensive maintenance program.

37 NRC at 14-15.

8- At the hearing on this issue, PG&E presented testimony by: Bryant Giffin, Manager of Maintenance Services; William Crockett, Manager of Technical and Support Services; David Vosburg, Director of the Work Planning Section, Maintenance Services Department; Steven Ortore, Director of the Electrical Maintenance Section, Maintenance Department; David Miklush, Manager of Operation Services; and Tedd Dillard, Supervisor of Component Programs for the Nuclear Division of Florida Power & Light Co.

9- The NRC presented testimony by Mary Miller, Senior Resident Inspector, DCNPP, Region V; Paul Narbut, Regional Team Leader, Region V, Division of Reactor Safety and Projects; and Sheri Peterson, Senior Project Manager, Office of Nuclear Reactor Regulation.

10- SLOMFP did not present testimony. However, SLOMFP introduced numerous documents generated by PG&E, such as Licensee Event Reports ("LERs"), Nonconformance Reports

("NCRs"), and other correspondence with NRC regarding issues relevant to maintenance. SLOMFP also introduced numerous NRC documents, including Inspection Reports and Notices of Violation, and correspondence with PG&E regarding maintenance issues. SLOMFP conducted cross-examination regarding both the written testimony submitted by PG&E and the NRC, as well as the LERs, NCRs, Inspection Reports, and other documents. In its Proposed Findings, SLOMFP relied extensively on the statements made by PG&E and the NRC in these documents.

<u>Standard of Review</u>

11- Under the Atomic Energy Act, 42 U.S.C. 2232(a), an applicant for a license must submit sufficient information for the NRC to find that the facility will "provide adequate protection to the health and safety of the public." 42 U.S.C. § 2133(d) also forbids the NRC from issuing a license if it would be "inimical" to public health and safety. Consistent with these statutory provisions, NRC regulations provide that the NRC may issue an operating license only upon a finding that (i) there is "reasonable assurance that the activities authorized by the operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with [NRC] regulations..." 10 C.F.R. § 50.57(a)(2). It necessarily follows that the license cannot be amended unless this standard continues to be met.

12- The safety standard in the Atomic Energy Act and NRC regulations is not one of absolute protection; however, it is an objective standard, and may not be tainted by cost considerations or risk-benefit balancing. Union of Concerned Scientists v. NRC, 824 F.2d 108 (D.C. Cir. 1987).

13- As the Court observed in Union of Concerned Scientists v. NRC, "adequate protection" is "not a self-defining concept; the Commission must decide the range and scope of safety measures that adequate protection requires." 824 F.2d at 117. In this case, the NRC does not have detailed regulations prescribing conditions for an adequate maintenance and surveillance program. Likewise, there are no regulations telling us how to judge the performance of PG&E to date, for purposes of evaluating the adequacy and effectiveness of its current program and whether it is likely to provide adequate protection to the public during the license extension term. Thus, we must articulate our own criteria for judging the adequacy of PG&E's program.

14- We think that the Institute for Nuclear Power Operations (INPO) guidance document, INPO 90-008 (MFP Exhibit 4) is helpful in defining the scope of issues that a maintenance program must address in order to provide adequate protection to public health and safety. In evaluating the adequacy of PG&E's program as demonstrated in its performance of maintenance and surveillance activities, we have also examined the following factors: First, the primary indicator of whether maintenance and surveillance is adequate is whether the essential systems relied on for safety are functioning and reliable. Have essential safety systems been neglected or poorly maintained, such that they fail or are unreliable? The more safety systems that have been put at risk by inadequate maintenance and surveillance, the graver our concern. Second, as we explained in our Prehearing Conference Order, even where individual maintenance problems are considered to be minor in nature, they "'are of more than minor concern, i.e., if left uncorrected they could lead to a more serious concern.'" Pacific Gas & Electric Co. (Diablo Canyon Nuclear Power Plant, Units 1 and 2), LBP-93-1, 37 NRC 5, 19 (1993), quoting 10 C.F.R. Part 2, Appendix C, IV. Third, do maintenance problems arise from a breakdown of multiple barriers that should have checked the problem in the first place? When many maintenance problems cause or contribute to the same incident, it raises the concern that the program is breaking down on too many levels to provide adequate defense-in-depth. Finally, do the same types of problems repeat themselves over and over again, indicating that PG&E is not learning from its mistakes? "[W]hen sufficient repetitive or similar incidents are demonstrated, aggregation and/or escalation of sanctions may well be in order." Prehearing Conference Order, 37 NRC at 19, quoting Tulsa Gamma Ray, Inc., LBP-91-40, 34 NRC 297, 305 (1991).

15- It is important to bear in mind that the license applicant bears the burden of proving that the reasonable protection standard will be met under the amended license. 10 C.F.R. 2.732. Thus, although an intervenor in an NRC licensing proceeding bears the burden of going forward with a contention that satisfies the requirements of 10 C.F.R 2.714(b), once the contention is admitted, it is the license applicant who must show that the facility can be operated safely.

<u>Importance of Maintenance and Surveillance to the Safety of DCNPP</u>

16- In this unusual case, PG&E seeks to extend the operating license term for DCNPP Units 1 and 2 for the lengthy periods of 13 and 15 years. The one other construction period recapture case in which a hearing was requested involved an extension of only 5 years. <u>Vermont Yankee Nuclear Power Corp</u>. (Vermont Yankee Nuclear Power Station), LBP-90-6, 31 NRC 85, 87 (1990).

17- PG&E has argued that this license amendment involves changes that are only "administrative" in nature, and "does not involve any alterations in plant design or operation." PG&E Proposed Findings at 3. However, there is one factor that clearly will change during the extended lifetime of DCNPP, and that is that the plant will age - for a much longer period than was originally contemplated when it was licensed. Indeed, throughout the evidence presented in this case, there are many examples of corrosion, erosion, and other forms of degradation that have already attacked various components in the plant. We note that some of these effects are the direct result of DCNPP's exposure to the corrosive effects of salt air and water: the plant sits directly beside the ocean, and takes in saltwater in its auxiliary saltwater cooling system. (See our discussion of Untimely Detection and Correction of Aging Effects.) We note that this aging process began as soon as construction of the plant commenced.

18- Thus, it is fundamental to the adequate protection of public health and safety that PG&E maintain a vigorous maintenance and surveillance program in order to detect and counteract the effects of aging on DCNPP. A sound maintenance and surveillance program is also vitally important because it is the principal means for detecting and correcting safety equipment that is malfunctioning for any reason, be it aging, personnel error, inherent defect, or whatever other cause.

FINDINGS REGARDING CONTENTION I

19- Our "findings" regarding the adequacy of PG&E's maintenance and surveillance program embrace both our factual findings and our legal conclusions regarding the significance of these facts with respect to the adequacy of PG&E's maintenance and surveillance program. The findings are divided into two sections, General Findings and Specific Findings. In the General Findings we describe our conclusions regarding the evidence as a whole, and discuss the significance of the patterns we see reflected in the many individual events that are described in the Specific Findings. Thus, the General Findings identify numerous deficiencies in PG&E's maintenance program, based on an aggregation of the evidence. The Specific Findings not only support these General Findings, but they contain our detailed conclusions regarding specific aspects of the maintenance and surveillance program, such as the adequacy of PG&E's program for maintaining environmental qualification of safety equipment, Corrosion of ASW Annubar, Diesel Fuel Oil and CO2 Piping, PG&E's Measuring & Test Equipment program, Control of Foreign Materials, and Storage and Handling of Lubricants.

GENERAL FINDINGS REGARDING CONTENTION I

**20- Finding: PG&E has not demonstrated that its maintenance and surveillance program is adequate to protect the health and safety of the public.**

21- As discussed below, the Board finds that the evidence in this case, taken as a whole, demonstrates that there are significant deficiencies in PG&E's maintenance and surveillance program. These deficiencies prevent us from concluding that the program provides reasonable assurance that public health and safety will be protected. In particular, we find significant problems in the four key areas that we identified above as important factors in weighing the health of a maintenance and surveillance program. First, inadequate maintenance and surveillance has resulted in the failure or unreliability of important safety systems; second, PG&E has shown a pattern of untimely or ineffective response to maintenance problems, thus demonstrating a lax and ineffectual maintenance and surveillance program; third, too many of PG&E's maintenance problems were the result of more than one error, resulting in the breakdown of the multiple barriers that should have prevented the problem in the first place; and fourth, PG&E demonstrates a repetitive pattern of failures in numerous areas, thus indicating programmatic deficiencies that go beyond the individual incidents involved.

22- We note at the outset that our conclusions are based, for the most part, on the voluminous documentation by PG&E and

NRC regarding PG&E's maintenance problems, including LERs, NCRs, NRC Inspection Reports and Notices of Violation, and other correspondence between PG&E and NRC. As a general matter, the Board finds these documents to be reliable and probative evidence regarding maintenance problems at DCNPP. We note that SLOMFP conducted cross-examination on each of these documents, and PG&E and the NRC were provided with the opportunity to address the statements made in these documents.

23- We are aware of the broad generalizations in NRC SALP report attesting to the adequacy of PG&E's maintenance program, and generalized testimony by PG&E witnesses to the same effect. However, we cannot reconcile these broad conclusions with the problems that we find in the details of PG&E's LERs and NCRs, and the NRC's Inspection Reports and Enforcement correspondence. We must consider all of the evidence, bearing in mind that PG&E bears the burden of persuading us that the problems identified in these detailed documents do not exist, are insignificant, or have been resolved adequately. We do not find this to be the case.

24- Moreover, we discount the generalized pronouncements of PG&E employees as self-interested. While PG&E called an outside expert, Tedd Dillard, who testified in glowing terms regarding DCNPP's maintenance program, Mr. Dillard admitted that he had spent only a few days at DCNPP, and that his paper review was "not very comprehensive." Tr. at 1481. Thus, the Board finds Mr. Dillard's testimony to have little probative weight. Moreover, the Board notes that while PG&E claimed Mr. Dillard was an independent outsider, he is a member of NUMARC, a nuclear industry group which has advocated against the imposition of more maintenance requirements on the industry. In fact, Mr. Dillard served on the NUMARC Committee which authored comments urging the NRC not to adopt its proposed maintenance rule. Tr. at 1476. While Mr. Dillard claims to have personally advocated the adoption of the maintenance rule [Tr. at 1486], his participation on the drafting committee raises some question regarding the strength of his convictions. In any event, as a loyal and active member of NUMARC, Mr. Dillard had an interest in portraying PG&E's maintenance program as adequate, if not exemplary. Tr. at 1476-1479.

**I. Failure or Unreliability of Important Safety Systems Reduction in Safety Margins**

**25- Finding: Most of PG&E's maintenance problems in the last several years have disabled or threatened essential safety systems.**

26- As a result of PG&E's maintenance deficiencies, safety systems have been disabled or their reliability has been threatened on many occasions, some for long periods of time. The loss or unreliability of a safety system undermines the redundancy of the system, and reduces the margin of safety on which the plant relies for safe operation.

27- For example, as described in the Specific Finding entitled Limitorque 2-FCV-37 Failed to Close, valve 2-FCV-37, was probably inoperable for some period of time between 1990 and 1993, due to improper maintenance in 1990. Given the essential role of this equipment in the safe operation of the plant, and the extensive length of time in which it may have been inoperable, the Board considers this to be a matter of serious concern. In the case of Containment Fan Cooling Unit Backdraft Dampers, the NRC found that the CFCU may have been operating with three inoperable CFCUs for almost an entire year. In these cases and others, improper maintenance and surveillance resulted in the actual disabling of safety systems. In other cases, improper maintenance and surveillance reduced or raised questions as to the reliability of safety components. Safety systems were disabled or threatened in all of the following instances:

Check Valves/IST Deficiency
Cable Failures
Wrong Size Motor Installed
Fuel Handling Building
Containment Personnel Airlock
Component Cooling Water (CCW) Heat Exchanger
Restoration of Electrical Panels
Auxiliary Building Ventilation System Inoperable
Containment Equipment Hatch
Manual Reactor Trip Caused by Failure of a Fuse for the Rod Control System
Safety Injection Emergency Core Cooling Accumulator Tanks
Corrosion (ASW annubar, diesel fuel oil and carbon dioxide piping)
Control of Measuring and Test Equipment
Diesel Generator 2-2 Failed to Achieve Rated Voltage
Missed Alert Frequency for ASW Pump 1-2 and CCW Valve CCW-2-RCV-16
Hold Down Motor Bolts on Centrifugal Charging Pumps
Reactor Coolant System Leakage

Reactor Cavity Sump Wide Range Level Channel 942A Inoperable
DCM Surveillance/Maintenance Requirements
Gas Decay Tank Surveillance Missed
Seismic Clips Not Installed
Control of Foreign Materials/Cleanliness/Housekeeping
Steam Generator Feedwater Nozzle Cracking
Procedural Controls During Shot Peening Operations
Limitorque Valve Failure
Motor Pinion Keys in Limitorque Valve Operators
Control of Lifting and Rigging Devices
Containment Ventilation Isolation
SI-1-8805A Failed to Cycle on Actuation Signal
Chemical and Volume Control System Diaphragm Leakage
Maintenance of Environmental Qualification of Electrical Equipment

(See Specific Findings for detailed discussions regarding these events.)

Inadequate and Incorrect Analyses of Safety Significance

28- **Finding: PG&E wrongly discounts the safety significance of many of its maintenance deficiencies. This not only results in an incorrect evaluation for purposes of evaluating the significance of the incident that occurred, but it also raises general questions about the adequacy of PG&E's judgment with respect to safety matters.**

29- In numerous LERs and NCRs, and in its testimony, PG&E has attempted to discount or dismiss the safety significance of many of the events described in the Specific Findings, on the ground that no accident occurred as a result. Tr. at 792. See SI-1-8805A Failed to Cycle on Actuation Signal, Restoration of Electrical Panels, Auxiliary Salt Water Crosstie Valve. As also discussed in the Specific Findings regarding these issues, the Board soundly rejects PG&E's reasoning, because it violates the basic principle of redundancy on which the assurance of safe operation is based. The principle of redundancy requires that for each safety system in the plant, there is an equivalent and independent safety system that is capable of performing the same safety function in the event the first system fails. Maintaining this redundancy is the fundamental responsibility of PG&E's maintenance and surveillance department. It is simply unacceptable to argue that there is "no safety significance" when redundancy of a safety system is eliminated through PG&E's error or neglect. Not only do we reject this type of reasoning, but we find that of itself, it represents a deficiency in PG&E's maintenance program, because it reflects poor judgment and a cavalier attitude by PG&E toward safety.

30. As discussed in our Specific Findings, in addition to its lack of understanding or appreciation of the redundancy requirement, the Board finds other significant deficiencies in PG&E's analyses of the safety implications of its maintenance and surveillance problems. <u>See</u>, <u>e.g.</u>, our Specific Findings on Check Valve/IST Deficiency, Restoration of Electrical Panels, ASW Saltwater Pump Crosstie Valve, 8805A Failed to Cycle on Actuation Signal. Given these deficiencies in PG&E's analyses of events after they have occurred, we question whether PG&E appreciates the safety significance of problems when they are occurring, and prioritizes its corrective actions accordingly. Indeed, the NRC questioned the adequacy of PG&E's judgment about the importance of the

CFCUs when it allowed them to remain inoperable for so long. See our Specific Findings on CFCU Backdraft Dampers.

## II. Untimely or Ineffective Response to Maintenance Problems

31- As we stated in our Prehearing Conference Order, when even minor safety problems are left uncorrected, they "could lead to a more serious concern." 37 NRC at 19. The Appeal Board has also found that in construction quality assurance issues, the important issue is "whether the problems were recognized and caught by the applicant almost from their inception and it quickly took steps to correct them." Pacific Gas & Electric Company (Diablo Canyon Nuclear Power Plant, Units 1 and 2), ALAB-756, 18 NRC 1340, 1348 (1983). Here we find an unacceptable number of instances in which PG&E either failed to detect a problem, or where it delayed corrective action for a significant period. In many other cases, PG&E did take corrective action, but it was partially or completely ineffective in preventing the recurrence of the problem. The net result was untimely and ineffective maintenance.

32- PG&E's deficiencies in these areas are exemplified in the following incidents:

Untimely Response

33- **Finding: PG&E has shown a pattern of responding to maintenance problems in a lax and untimely manner.**

34- The following events illustrate PG&E's untimeliness in responding to maintenance problems:

Cable Failures
Limitorque 2-FCV-37 Failed to Close
Safety Injection Emergency Core Cooling System Accumulator Tanks
Corrosion
Control of Measuring and Test Equipment
Hold Down Motor Bolts on Centrifugal Charging Pumps
Reactor Cavity Sump Wide Range Level Channel 942A Inoperable
Containment Fan Cooling Unit
Control of Foreign Material
Main Feedwater Pump Overspeed Trip
Containment Ventilation Isolation
Auxiliary Saltwater Pump Crosstie Valve
Main Feedwater Check Valve

(<u>See</u> Specific Findings for detailed discussions regarding these incidents.)

<u>Previous Corrective Action Failed to Prevent Recurrence</u>

35- **Finding: In many cases, PG&E had the same or similar problem reoccur after PG&E had attempted to resolve it. This shows an ineffectual maintenance program that is unable to take timely and effective corrective action with respect to maintenance problems.** The following examples illustrate this problem:

Storage and Handling of Lubricants
Restoration of Electrical Panels
Containment Equipment Hatch
Manual Reactor Trip caused by Failure of Fuse for Rod Control System
Safety Injection Emergency Core Cooling System Accumulator Tanks
Corrosion
Control of Measuring and Test Equipment
Centrifugal Charging Pump; Degraded Coupling 2-1
Reactor Cavity Sump Wide Range Level Channel 942A Inoperable
Seismic Clips not Installed
Containment Fan Cooling Unit
Control of Foreign Material
Procedural Controls during Shot Peening Operations
Unplanned ESF Actuations due to Personnel Error
Main Feedwater Pump Overspeed Trip
Containment Ventilation Isolation
Reactor Trip on Steam Generator Low Level

(See Specific Findings for detailed discussions regarding these events.)

Untimely Detection and Correction of Aging Effects

36- PG&E admits that "equipment aging management is inherent in maintenance and surveillance." PG&E Ts. at 62. Yet, PG&E has not thoroughly nor effectively addressed the problems of corrosion, degradation and aging of equipment. For instance, with respect to Corrosion of ASW Annubar, Diesel Fuel Oil and Carbon Dioxide Piping (See Specific Findings), PG&E allowed for extensive corrosion on these valves by (1) its failure to maintain the protective coating on these pipes; (2) its failure to keep the trench clear in order to prevent standing water (the cause of the corrosion); and (3) its failure to provide adequate surveillance to detect/prevent this degradation.

37- Moreover, as noted elsewhere, DCNPP is situated in a salt air and water environment - elements that are particularly corrosive. PG&E's maintenance and surveillance program has not proven itself to be adequately vigilant or thorough to prevent the effects of corrosion, degradation and aging on its systems, components and equipment at DCNPP. Evidence of this problem can be found in the following events:

Cable Failures
Chemical and Volume Control System Diaphragm Leakage
Fuel Handling Building
Component Cooling Water Heat Exchanger
Limitorque 2-FCV-37 Failed to Close
Safety Injection Emergency Core Cooling System Accumulator Tanks
Corrosion

Reactor Coolant System Leakage
Containment Fan Cooling Unit
Steam Generator Nozzle Cracking
Auxiliary Saltwater Pump Crosstie Valve
Testcock Valve on Diesel Generator

(See Specific Findings for detailed discussions regarding these events.)

## III. Breakdown of Multiple Barriers

38- In a significant and unacceptable number of cases, personnel errors were made on the same task by several individuals, including the person who initially did the work and the people who were responsible for verifying the accuracy of the work. As a result, supervisory or confirmatory activities, i.e. what PG&E calls the "checks and balances" or "barriers" that were intended to discover the error and correct or prevent it, became additional causes of the problem. MFP Exhibit 49 at 6. Thus, PG&E's "defense-in-depth" against maintenance errors breaks down when this system of checks and balances fails. The Board finds that this record is replete with so many examples of such breakdowns, that it indicates a programmatic deficiency in PG&E's maintenance program.

39- For instance, in the case of Missed Alert Frequency STP for Auxiliary Salt Water Pump 1-2 (See Specific Findings), the individual conducting the test failed to recognize that the data was incorrect. The shift foreman then failed to recognize that the wrong pump curve was attached to the data package. The test reviewer then incorrectly determined that the results were satisfactory. Thus, the two people who should have caught the first error also made errors, and as a result the multiple barriers that were designed to detect the error and prevent the problem were broken.

40- In the case of Wrong Size Motor Installed (See Specific Findings), a similar series of personnel errors occurred: a "work planner" misread a DCN during work order development. Then three other individuals, who were responsible for checking the correctness of the installation of the motor, failed to identify the fact that the wrong one had been installed.

41- Yet another example of failed "barriers" occurred in the case of Auxiliary Building Ventilation System Inoperable. In that case, a system engineer altered an original clearance without understanding the impact it would have on the system. Moreover, none of the individuals responsible for reviewing the clearance understood its impacts either. As PG&E explained,

> If the clearance had not been altered in the work the work in the field could have been performed as it had, as successfully accomplished in the past, without a mishap. However, because no one person is expected to know all of the intricacies associated with any system or maintenance activity, a series of checks and balances (i.e. review) are incorporated into the process to identify items that could cause a problem. All of these barriers (i.e. reviews) did not recognize the conditions that could be created by altering the clearance. As a result, the last barrier that could have prevented the mishap was also determined to be a Root Cause. MFP Exhibit 49 at 6.

42- Other examples of failed checks and balances or multiple barriers are:

Containment Fan Cooling Unit (CFCU) Backdraft Dampers
Control of Lifting and Rigging Devices
ASW Pump Vault Drain Check Valves
In-Service Prompt Test Data Questionable

(<u>See</u> Specific Findings for detailed discussions of these incidents.)

## IV. Repetitive Patterns of Failure

43- The Board finds that many of the incidents described in the Specific Findings, when viewed together, show repetitive patterns of the same or similar mistakes and problems. As discussed below, we find that these patterns show deficiencies in PG&E's maintenance and surveillance program in the following respects:

### <u>Lack of Communication and/or Coordination</u>

**44- Finding: PG&E's maintenance and surveillance program is deficient in its communication and coordination between different groups of individuals and/or departments.**

45- The evidence in this case shows that maintenance and surveillance problems at DCNPP are too often caused by poor coordination and communication, either between the maintenance department and other departments such as engineering or instrument and control, or within the maintenance department itself. For instance, in the case of Auxiliary Building Ventilation System Inoperable, PG&E found there was "personnel error resulting from poor communication." The "craftsman did not notify the Mechanical Maintenance Foreman that the Operations Shift Foreman had only approved the closure of Dampers M-5A and M-5B" and not MD-3, which was erroneously closed. See Specific Findings. Related to this problem is the lack of sufficient management attention. This is a problem which repeats itself over and over again, despite alleged efforts by PG&E to improve communication.

46- The following are examples of incidents in which a lack of coordination, communication or management involvement played a role in its occurrence:

Insufficient Communication:

Auxiliary Building Ventilation System Inoperable
Reactor Trip on Steam Generator Low Level
Corrosion
Motor Pinion Keys in Limitorque Motor Operators
Procedural Controls during Shot Peening
Main Feedwater Check Valves
Control of Lifting and Rigging Devices
Containment Ventilation Isolation Signals
Testcock Valve on Diesel Generator

Insufficient Coordination between Multiple Groups:

Seismic Clips not Installed
Restoration of Electrical Panels
Control of Lifting and Rigging Devices
Limitorque Valve Failures (Communication with vendor)

Insufficient Management Involvement:

Control of Measuring and Test Equipment
Containment Fan Cooling Unit

(See Specific Findings for detailed discussions of these events.)

Previous Maintenance Errors Caused Undetectable Problems

47- **Finding: PG&E has demonstrated a pattern of creating undetectable failures through improper maintenance.**

48- In a number of cases, the Board found that PG&E's own maintenance activities were done incorrectly, and in some cases created undetectable maintenance problems. Sometimes these problems were found through testing, but in too many cases they were not found until they caused component failure or were discovered by accident. The difficulty of detecting these problems raises a serious concern about whether PG&E has adequate measures to ensure that overhaul of the internal workings of components is adequately supervised and checked. This occurred in the following instances:

Limitorque 2-FCV-37 Failed to Close
Unit Shutdown Due to Inoperable High Pressure
  Turbine Stop Valve
Diesel Generator 2-2 Failed to Achieve Rated Voltage
Limitorque Valve Failure
SI-8805A Failed to Cycle on Actuation Signal
Auxiliary Feeder Breaker 52HH13 Failed to Open

(See Specific Findings for detailed discussions of these events.)

Inadequate/Improper Surveillance

49- **Finding: Routine surveillances, tests and inspections at DCNPP are inadequate to ensure the continued safe operation of the plant.**

50- The Board finds that, as demonstrated by the following examples, there is a repetitive pattern of missed surveillances, improperly performed tests and a lack of monitoring activities for essential equipment at DCNPP:

Check Valves/IST Deficiency
Cable Failures
Chemical and Volume Control System Diaphragm Leakage
Fuel Handling Building
Component Cooling Water Heat Exchanger
Missed Alert Frequency STP for ASW Pump 1-2 and CCW Valve
In-Service Prompt Test Data Questionable
Reactor Coolant System Leakage
Reactor Cavity Sump Wide Range Level Channel 942A Inoperable
Gas Decay Tank Surveillance Missed
DCM Surveillance/Maintenance
Containment Fan Cooling Unit
Steam Generator Nozzle Cracking
Procedural Controls during Shot Peening Operations
Auxiliary Saltwater Pump Crosstie Valve
Testcock Valve on Diesel Generator
Containment Personnel Airlock

(See Specific Findings for detailed discussions regarding these incidents.)

51- PG&E attempts to discount the significance of these surveillance problems, characterizing them as isolated incidents. However, they must be seen as a whole for the repetitive and unresolved pattern they present.

52- PG&E also attempts to minimize the significance of its missed surveillances by claiming that it has missed only 65 surveillances in the last ten years. Tr. 844-853. However, this claim is misleading, because PG&E counts only the root cause of the missed surveillance, and not the missed surveillance itself. Thus, in the case of Containment Personnel Airlock, a surveillance was missed 17 times - but only counted by PG&E as one missed surveillance.

Personnel Errors

**53- Finding: PG&E has demonstrated a repetitive pattern of personnel errors which jeopardize the safety of the plant.**

54- The record of this case shows the occurrence of many personnel errors during the past several years, some of them having significant safety consequences or potential safety consequences. In its testimony, PG&E consistently characterized these personnel errors as isolated, unrelated incidents. The individual significance of many of these errors individually may not appear noteworthy. Yet, the Board finds that when so many mistakes are being made by so many people, there is cause for concern about competence and/or training of personnel. The following incidents of personnel error support our finding that there is a repetitive personnel error which indicates a deficiency in PG&E's maintenance and surveillance program:

Personnel Error due to Inattention to Detail

Storage and Handling of Lubricants
Control of Measuring and Test Equipment
Missed Alert Frequency STP for ASW Pump 1-2 and CCW Valve
Unplanned ESF Actuations Due to Personnel Error
Containment Ventilation Isolation

Personnel Error due to Failure to Follow Procedures:

Storage and Handling of Lubricants
Manual Reactor Trip Caused by Failure of Fuse for Rod Control System
Control of Measuring and Test Equipment
Procedural Controls during Shot Peening Operations
Unplanned ESF Actuations due to Personnel Error
Control of Lifting and Rigging Devices
Containment Ventilation Isolation
Reactor Trip on Steam Generator Low Level

Auxiliary Salt Water Pump Vault Drain Check Valves

<u>Personnel Failure to Self-Verify:</u>

Wrong Size Motor Installed
Unplanned ESF Actuations due to Personnel Error

**<u>Inadequate Procedures</u>**

55- **Finding: Procedures or work instructions for personnel are not adequate to ensure that work activities are performed adequately.**

56- The Board finds that in recent years, a significant number of incidents have been identified in which inadequate procedures, instructions or guidelines were provided to the personnel performing the maintenance activities and which contributed to the occurrence of these events. The Licensing Board finds the number sufficient to reflect a pervasive problem with an essential element of the maintenance and surveillance program at DCNPP. These events include:

Check Valves/IST Deficiency
Auxiliary Building Ventilation System Inoperable
Restoration of Electrical Panels
Containment Equipment Hatch
Limitorque 2-FCV-37 Failed to Close
Corrosion
Centrifugal Charging Pump; Degraded Coupling 2-1
Diesel Generator 2-2 Failure to Achieve Rated Voltage
In-Service Prompt Test Data Questionable
Gas Decay Tank Surveillance Missed
Seismic Clips not Installed
Control of Foreign Material
Procedural Controls during Shot Peening Operations
Limitorque Valve Failure
Motor Pinion Keys in Limitorque Motor Operators
Control of Lifting and Rigging Devices
Reactor Trip on Steam Generator Low Level
Auxiliary Salt Water Pump Vault Drain Check Valves
SI-1-8805A Failed to Cycle on Actuation Signal

(*See* Specific Findings for detailed discussions of these events.)

Manufacturing/Vendor Deficiencies and Internal Defects

57- **Finding: PG&E does not have an effective program for detecting manufacturing deficiencies or internal defects.**

58- Manufacturing/vendor deficiencies are not detected in an effective nor timely manner at DCNPP. Instead, an unacceptable number of inherent or internal component defects are discovered by chance, sometimes when the component fails. In fact, ironically, in two of the incidents listed below (Motor Pinion Keys in Limitorque Motor Operator Valves and Testcock Valve on Diesel Generator), the discoveries were made because of incorrectly performed surveillance tests.

59- It is the responsibility of the maintenance and surveillance organization to identify such deficiencies before they become self-evident. PG&E has failed to do so, as evidenced in the following examples:

Centrifugal Charging Pump; Degraded Coupling 2-1
Hold Down Motor Bolts on Centrifugal Charging Pumps
Limitorque Valve Failure
Motor Pinion Keys in Limitorque Motor Operators
Testcock Valve on Diesel Generator
Main Feedwater Check Valve
SI-1-8805A Failed to Cycle on Actuation Signal
Snubber at Pipe Support
Unit Shutdown due to Inoperable High Pressure Stop Valves

(*See* Specific Findings for detailed discussions regarding these events.)

Financial Considerations

**60- Finding: PG&E's decisions regarding what is needed to maintain the plant in a safe condition have been unduly influenced by economic considerations.**

61- Due to a unique rate payer settlement, PG&E considers cost before making necessary repairs, often without regard to ensuring the safest possible operation. Under DCNPP rate payers settlement, the cost of maintenance cannot be passed onto the rate payers. The Licensing Board finds that this fact influences the "priority list" that is utilized by PG&E management to determine what maintenance is to be performed. Tr. at 814. The record of this case shows that in a number of instances, PG&E postponed needed maintenance activities on the basis of their cost:

Fuel Handling Building
Safety Injection Emergency Core Cooling System Accumulator Tanks
Containment Fan Cooling Unit
Main Feedwater Pump Overspeed Trip
Containment Ventilation Isolation
Fire in Electrical Panel

(*See* Specific Findings for detailed discussions regarding these events.)

## SPECIFIC FINDINGS REGARDING CONTENTION I

### MAINTENANCE OF ENVIRONMENTAL QUALIFICATION OF ELECTRICAL EQUIPMENT

MFP Exhibit T-1: NRC Information Notice 89-30: High Temperature Environments at Nuclear Power Plants (3/15/89)
MFP Exhibit T-2 : PG&E Temperature Monitoring Procedure MP E 57.8A
MFP Exhibit T-3: Sargent & Lundy Engineering Report #8664-03, "Effect of Localized High Temperatures Upon EQ Components" (2/27/90)
MFP Exhibit T-4: Teletemp Temperature Sticker Data, Units 1 and 2

Transcript pages: 1844-2041

**62- Finding: Maintenance of the environmental qualification of electrical equipment that is important to safety is fundamentally important to the safe operation of DCNPP.**

63- As the Commission has observed,

> fundamental to NRC regulation of nuclear power reactors is the principle that safety systems must perform their intended functions in spite of the environment which may result from postulated accidents. Confirmation that these systems will remain functional under postulated accident conditions constitutes environmental qualification. Petition for Emergency and Remedial Action, CLI-80-21, 11 NRC 707, 711 (1980).

Accordingly, pursuant to 10 C.F.R. § 50.49, electrical equipment which is important to safety (hereinafter "safety components" or "safety equipment") and which is subject to a harsh accident environment must be qualified to withstand the conditions to which it may be exposed during an accident.

64- The "qualified life" of the component is the period of time during which it can be expected to remain qualified to function in the accident environment. In initially determining the qualified life of a safety component, the component or a prototype is "subjected to aging for that amount of time and then has been qualified to the local conditions subsequent to that aging." Tr. at 1842. The normal operating temperatures to which the equipment is exposed during its service life constitutes one of the parameters that is factored in when the qualified life of the component is determined. Id. Thus, the environmental qualification of any given safety component is based on certain assumptions about the maximum temperature that it will be exposed to during its normal operating life. Id.

65- If the normal operating temperature exceeds the temperature assumed in originally qualifying the equipment, the qualified life must be shortened and the equipment must be changed out earlier than originally expected. Tr. at 1843-44.

66- At DCNPP, the qualified life of a safety component is based on the bulk ambient temperature of the area in which the component is located. Tr. at 1856. However, PG&E recognizes that localized temperatures may be higher than ambient temperatures as defined in the "binders" which document the basis for the qualified life of each safety component. Id.

67- In Information Notice 89-30, High Temperature Environments at Nuclear Power Plants (3/15/89), MFP Exhibit T-1, the NRC also notified licensees that:

> It is important for licensees to be aware that there are areas within the plant where the local temperatures may

exceed equipment qualification specifications even when the bulk temperature, as measured by a limited number of sensors, is indicating that it is lower than the qualification temperature. Tr. at 1844.

68- At that time, PG&E had already begun a program to identify hot spots for purposes of monitoring areas in the plant where safety equipment might be exposed to unexpectedly high temperatures. Tr. at 1845. PG&E hired a consultant, Sergeant and Lundy ("S&L"), to help with this effort. Id. PG&E also issued a procedure for implementing the temperature monitoring program, MPE-57.8A, MFP Exhibit T-2. Id. The procedure was last revised in 1992. Tr. at 1891.

69- As part of its program for maintaining the qualification of safety equipment, PG&E monitors certain pieces of equipment located in "hot spots," or areas subject to particularly high temperatures. The purpose of this monitoring program is to determine whether operating temperatures in those areas stay within the limits that were assumed when the equipment was qualified. Tr. at 1843.

70- To monitor localized "hot spots," MPE-57.8A provides for the placement of "teletemp stickers" directly on individual safety components, to determine the temperature to which they are exposed. The stickers are tabs with mylar faces. The squares on the stickers contain temperature-sensitive chemicals which turn color when they are exposed to certain temperatures. The stickers indicate the highest temperature that the component has been exposed to. Tr. at 1846, 1855.

71- The teletemp stickers generally give readings in 10 degree intervals. When the 150 degree window changes color, for instance, that means the component experienced a temperature that was between 150 and 159 degrees. PG&E testified to the importance of applying conservatism in using the teletemp readings. Tr. at 1861. Thus, it must be assumed that the safety component being evaluated experienced the highest possible temperature that is indicated by the changed teletemp sticker window. If the 150 degree window changed, then it should be assumed that the component experienced a temperature as high as 159 degrees. Id.

72- At refueling outages, maintenance personnel remove the stickers and adhere them to a sheet. Tr. at 1847. Occasionally the stickers are damaged on removal. Id. The temperature is recorded on a form. Id.

73- The maintenance department is only responsible for applying the stickers and collecting the information. The actual analysis is done by the design engineering group in San Francisco. Tr. at 1850.

74- PG&E testified that the teletemp monitoring results are interpreted in a conservative manner. Tr. at 2042-43. According to PG&E, unless there is some reason to believe that a high temperature was only transitory, it assumes that the highest temperature recorded by the teletemp sticker was the temperature the component was exposed to throughout the period that the teletemp sticker was used, i.e. the period since the last refueling outage when that teletemp sticker was installed. Tr. at 1851, 2042-43.

75- The need for conservatism arises from the nature of the teletemp stickers, which only monitor peak temperatures experienced by the equipment. Thus, the sticker does not tell PG&E the length of time during which that peak temperature existed. A high temperature may have been experienced for a matter of hours, days, weeks, or months. In order to ensure that the equipment remains environmentally qualified, it is essential to take a conservative approach in interpreting these stickers.

76- Another reason for the need for conservatism in evaluating the temperature readings is that some safety equipment is extremely vulnerable to temperature changes. As the NRC noted in Information Notice 89-10, "Electrical cables are vulnerable to degradation when exposed to high temperatures that exceed their design EQ temperature even for a short period." Id. at 2. MFP Exhibit T-1 at 2. (The Board notes that, through an error by SLOMFP, Exhibit T-1 was not moved into the record. However, PG&E testified that it was familiar with this Bulletin. Tr. at 1844. Pursuant to 10 C.F.R. § 2.743(i), we take official notice of the fact that the vulnerability of cables to heat-induced degradation was one of the factors which prompted the NRC to issue Information Notice 89-10, in order to alert licensees to the need to monitor localized high temperature environments.)

77. **Finding: The teletemp sticker program is important because peak temperatures may vary significantly over time.**

78. PG&E also testified that since the original hot spots were identified early in DCNPP operation, PG&E has seen "very, very little changes in temperature over our operating experience." Tr. at 2043. But this is not borne out by the teletemp data in SLOMFP Exhibit T-4. For instance, teletemp readings for valve 8000B and conduit KT319 in Unit 1 ranged from 140 to 170 degrees. This means that the temperature variation could have been as high as 39 degrees over the course of four refueling outages between 1988 and 1992. See Table A of these proposed findings. Teletemp readings for valve FCF-440 in Unit 2 ranged from 120 to 160 degrees, or 49 degrees, over the same period. See Table B. Readings for valve 8000A ranged between 140 degrees and 180 degrees, also a 49 degree difference. Id. Teletemp readings for valves FCV-38 ranged from 160 to 220 degrees F between 1988 and 1991 (no stickers were found in 2R5, the 1992 refueling outage) - a potential 69 degree difference. Given these potential variations in temperatures to which safety components may be exposed, the Board finds that the teletemp monitoring program is essential for the purpose of supplementing bulk temperature measurements and maintaining reasonable accuracy in PG&E's assumptions about the service conditions experienced by environmentally qualified safety components.

**79- Finding: PG&E's teletemp monitoring program is not sufficiently reliable or accurate to provide information that is needed to evaluate the status of environmental qualification of safety equipment and the need for replacement.**

80- In examining the records kept by PG&E of its teletemp measurements, we found many instances in which there were no measurements or measurements were incomplete. The following are examples of these deficiencies.

No teletemp readings for some components:

81- In each refueling outage, there are at least several instances in which no teletemp measurements were recorded. Sometimes data sheets are missing entirely. At other times, PG&E noted on a data sheet that the information was missing. (We note here that PG&E testified that unless a box on the form is checked showing that this is a new piece of equipment for which there was no sticker to be removed, "N/A" or "NA", as written on the forms, probably means either that only one sticker was found, that a sticker was illegible, that there was no sticker below, or they couldn't move a sticker without damaging it. Tr. at 1887.)

82- For instance, for teletemp recordings in outage 1R5 (10/92), there were no data sheets and thus no recorded temperature measurements for valves 8078A, 8078B, 8078D, general area (KT251)115', general area (KT251)133', conduit K5787, conduit above and behind FCV-38, conduit KR027, and conduit KR029. Table A. A data sheet was kept for FCV-750, but noted that "no temp stickers found." Id. For outage 1R4 (8/90-3/91), there were no data sheets for valves 8078A, 8078B, 8078D, general area (KT251)115', general area (KT251)133' conduit above and behind FCV-38, conduit KR027, or conduit KR029. PG&E kept a data sheet for FCV-37 but reported that no stickers were found. For outage 1R3 (11/89), there were no data sheets for general area (KT251)115', general area (KT251)133' conduit above and behind FCV-38, general area (ceiling), general area (K6442), general area (K880), conduit KT319, or conduit K6467.

83- For outage 2R5 (4/93), there were no data sheets for general area (K6481) or general area (near FCV-38, GW/115). PG&E kept data sheets but reported that no stickers were found for FCV-38 and general area (K6442). Table B. For outage 2R4 (9/91), there were no data sheets for general area (K6126) GW/115, general area (K912), general area (near FCV-38, GW/115), or general area (K1296). PG&E kept data sheets but reported that no stickers were found for FCV-95 and general area (K1768). For outage 2R3 (3-4/90), there are no data sheets for FCV-750, 8078A, 8078B, 8078C, 8078D, general area (K6126) GS115, general area (near FCV-38, GW/115), or general area (K1296). PG&E kept data sheets but reported that no stickers were found for FCV-749, RE-73, RE-74, and K129. PG&E kept data sheets but recorded no data and gave no explanation for general area (K6126) GW/117, general area (K6126) 126, general area (K6126) GW/133, general area (K6126) 135, and general area (K912).

84- PG&E's inconsistency in recording and reporting teletemp data raises a number of concerns. First, although PG&E's performance clearly has improved since the program began in 1988, PG&E continues to have considerable gaps in recording teletemp data. By itself, this pattern of inconsistency is a matter of serious concern in a program that is so fundamental to safety.

85- Moreover, these gaps sometimes extend over a period of several refueling outages, thus resulting in long periods when there is no information about the qualification status of the component. For instance, PG&E did not record any teletemp data for valves 8078A, 8078B, 8078C, or 8078D, in 1R4 <u>or</u> 1R5. Thus, PG&E has not measured peak localized temperatures for these components since 11/89, or four years. During 1R2 (6/88), PG&E collected temperature data for general area (KT251)115' and general area (KT251) 133' - but has not gathered data in any refueling outage since then. Thus, it has been five and a half years since peak localized temperatures were measured for these components. We note here that the temperature measurements taken in 1988 were relatively high for the 133' elevation - 140 and 160 degrees. Table 1. As PG&E testified, 160 degrees is "quite warm." Tr. at 1888.

Stickers for top and bottom of component not present:

86- MPE 57.8A generally requires the placement of at least two stickers on each component - one on the top and one on the bottom. MFP Exhibit T-2 at 3, Appendix 8.2. This is because the temperatures may vary from top to bottom. Tr. 1889. In fact, they may vary considerably. For example, top and bottom measurements taken during 1R5 (10/92) varies by 10 degrees (FCV-95), 20 degrees (FCV-441, general area (K880)), and 50 degrees (general area (ceiling)). Top and bottom measurements taken during 2R4 varied by 10 degrees (general area, GW/135), at least 30 degrees for valve 8000B (the higher measurement was at maximum possible sticker reading, and therefore could have been higher), and 40 degrees (FCV-38, FCV-441).

87- Contrary to the requirement of MPE 57.8A, in many instances PG&E has not maintained two stickers on the safety components. See Tables A and B. This problem dates from 1988, when the first teletemp measurements were recorded, to the most recent refueling outages for Units 1 and 2. The Board is concerned about the level of accuracy of these teletemp measurements, given the many instances in which PG&E recorded only one measurement rather than the required two measurements. This pattern of failure to install or record both stickers - which should not be that difficult - also raises a question as to whether PG&E is adequately committed to this program to assure that it will be carried out faithfully and accurately.

88- Moreover, we are particularly concerned that in some cases, the failure to collect complete data for a given component spans several refueling outages, as in the case of Unit 2, general area (K6126) at GW/115, GS/117, GW/126, GW/133, and GW/135. In 2R5, only GW/115 had both teletemp stickers. In 2R4, although GW/135 had both stickers, there was no data at all for GW/115, and the other locations had only one sticker. In 2R3, again there was no data for GW/115. PG&E kept data sheets for the other locations but reported no measurements, and provided no explanation. Thus, data for this location are either incomplete or absent for a number of years.

89- Similarly, in the general area near FCV-38, GW/115, PG&E recorded teletemp measurements of 120 and 140 degrees during 2R2 (11/88). No teletemp measurements were recorded in 2R3 (3/90), or 2R5 (4/93). Only one teletemp measurement of 160 degrees was recorded in 2R4 (10/91). Thus, for four refueling outages there is only one complete set of teletemp measurements. Moreover, the range of temperature readings is significant - 120 to 160 degrees F - thus showing that it was important to gather complete temperature data for this component.

Adequate range of temperatures on stickers not present:

90- Some components may experience a wide range of temperatures; thus, MPE-57.8A requires PG&E to install a second set of stickers that can register higher temperatures. PG&E testified that this may not have been the case five years ago. However, even in the two most recent refueling outages, PG&E neglected to install a second set of stickers on FCV-440 during 1R5, and on FCV-440, FCV-441 and general area (ceiling) during 1R4. We also note that data recorded during 2R4 shows that PG&E did not use teletemp stickers with a sufficient range of temperatures to record the peak temperatures to which valves 8000B and 8000C were exposed. PG&E recorded the peak temperatures for these components as 190 degrees for 8000B and 200 degrees for 8000C. However, these are not necessarily the peak temperatures to which the components were exposed - they are just the highest temperatures that were capable of being recorded by the teletemp stickers.

91- We also note that in refueling outage 1R2, both stickers for FCV-38 registered 200 degrees, the highest possible measurement on the stickers. Clearly, the temperatures to which this valve was exposed could have been higher. This should have been an indication to PG&E that it should add more stickers to provide for a greater range of measurements; yet, in the next refueling outage, PG&E used the same range of teletemp stickers, and again obtained measurements of 200 degrees. It was not until the fourth refueling outage that PG&E began to use four stickers. While we recognize that FCV-38 is not included in PG&E's EQ program [Tr. at 1882], PG&E has made a conscious decision to include it in the teletemp monitoring program, and thus its failure to respond quickly to the need for a greater range of temperature measurement capability is a matter of concern to the Board.

Inadequate procedures for teletemp monitoring:

92- The Board finds that PG&E's procedures for teletemp sticker installation are confusing, and that as a result it is difficult to determine exactly where stickers should be installed and monitored. Appendix 8.2 of MPE-57.8A purports to be a list of "Electrical Equipment With Teletemp Stickers." In examining the data sheets compiled by PG&E in monitoring the teletemp stickers, however, the Board finds that there are many data sheets for locations which do not correspond to locations identified in Appendix 8.2. For instance, conduit KR6467 was monitored in 1R4 and 1R5 but not in earlier refueling outages. Was this conduit added to the program without revising the procedure? If so, how do technicians know that they should gather data from that location? How do the technicians know how many sets of teletemp stickers they should install there? During 1R4 and 1R5, PG&E took teletemp measurements for conduits KT319 and K5787. K5787 was also monitored during 1R3. Yet, MPE-57.8A contains no mention of these two locations. When were these conduits added to the program? How do technicians know they should be monitored, or where and how to install the stickers, if these conduits are not included in the procedures?

93- We also note that MPE-58.7A discusses only the installation and removal of stickers. It provides no instruction on how to record the data from the stickers onto the data sheets. Because most components have two stickers, and some may have as many as four, this could be confusing. We also find it confusing that PG&E uses the same term - N/A or NA - to denote two entirely different sets of circumstances. As discussed above, N/A or NA may refer to the fact that a new piece of equipment was installed, or to the fact that a teletemp sticker was not fcund or could not be read. While the form has a box that is to be checked off if the first meaning of the term is being applied (i.e., that it is a new piece of equipment and therefore does not have a sticker), the use of the same term for two purposes invites error. For these reasons, we are disturbed - but not surprised - to find that one of the data sheets (for valve 8000B, during 1R4), contains a complaint that "procedure should explain how to read stickers."

94- Conclusion: As we have stated above, it is fundamentally important that PG&E have an adequate program for maintaining environmentally qualified safety equipment. This includes monitoring equipment where temperatures are known to be high, to ensure that the normal operating temperature is not higher than the conditions to which the equipment was originally aged. If it is, the qualified life must be reduced and the equipment must be replaced. The Board finds that PG&E's program for monitoring these localized high temperatures is deficient in that it is not being carried out in a consistent and accurate manner, and that PG&E does not have adequate procedures to ensure that it can be carried out properly.

CHECK VALVES/IST DEFICIENCY

MFP Exhibit 6: NCR DCO-93-TP-N028 (7/29/93)
MFP Exhibit 7: LER 1-84-047-00 (7/26/93)
MFP Exhibit 8: NCR DCO-93-TP-N027 (7/8/93)
MFP Exhibit 9: NCR DCO-93-TN-N011 (5/6/93)
MFP Exhibit 10: NCR DCO-91-TN-N048 (2/7/92)
MFP Exhibit 11: NCR DCO-91-TN-N026 (4/12/91)
MFP Exhibit 13: LER 1-92-001-00 (4/30/92)

Transcript pages 600-622

95- The NRC issued Information Notice 88-70, "Check Valve Inservice Testing Program Deficiencies" (8/29/88) to notify licensees of potential problems with check valve in-service testing (IST). NCR DCO-91-TN-N026 (4/12/91), MFP Exhibit 11 at 2. As summarized by PG&E, the NRC "was concerned that check valves included in IST programs were not always tested in both the open and closed positions to verify their ability to perform a safety-related function." Id. The NRC had found that "no reverse flow operability tests were being performed on check valves other than those valves used for containment isolation and reactor coolant system pressure boundary isolation." Id.

96- NRC Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs," dated 4/3/89, identified similar generic concerns and required that implementing test procedures be reviewed and revised as necessary within six months of receipt of the generic letter. Id.

97- PG&E initiated a review of safety-related check valves at DCNPP. LER 1-92-001-00 (4/30/92), MFP Exhibit 13 at 2.

**98- Finding: As a result of PG&E's review, a multitude of deficiencies in the Check Valve/IST program have been identified and continue to be discovered.**

99- On 12/7/89, the DCNPP Plant Staff Review Committee reviewed its response to NRC IN 88-70. Two check valves (8998A and 8998B) were found not to have been leak tested in accordance with ASME Section XI, i.e., they were being tested in the open position to verify flow, but were not being tested in the closed position. MFP Exhibit 13 at 3.

100- In June of 1990, as a result of an August 1989 information letter from Westinghouse, PG&E also found that five check valves on potential leakage paths to the refueling water storage tank (RWST) were not being verified to close by in-service testing. MFP Exhibit 11 at 2. PG&E reported the IST deficiencies for these seven check valves (check valves

9002A, 9002B, 8924, 8977, 8981, 8998A and 8998B) in LER 1-84-044-00 (7/16/90). See MFP Exhibit 11 at 3.

101- On 4/2/91, PG&E submitted LER 1-84-044-01 to report that two other check valves - auxiliary feedwater steam supply check valves MS-5166 and MS-5167 - were not being fully tested. See MFP Exhibit 13 at 3.

102- On 5/24/91, during a review of STP [illegible], PG&E discovered that valves SI-8900A-D, SI-8905A-D and SI-8819A-D were not individually measured for full flow, contrary to the recommendations of GL 89-04. NCR DCO-91-TN-N048 (2/7/92), MFP Exhibit 10 at 1. PG&E attributed the root cause to "personnel error because the responsible personnel did not recognize the need to measure the flow through the subject valves individually." Id. PG&E found that a contributory cause was "lack of understanding of GL 89-04 requirements and confusion of corrective actions from previous NCRs." Id.

103- On 12/11/91, to support a request for relief from certain in-service testing requirements for check valve SI-8981, PG&E committed to perform full-stroke testing of check valve SI-8981 following disassembly inspections. NCR DCO-93-TN-N011, Rev. 00 (Draft: 5/6//93), MFP Exhibit 9 at 2,3. On 6/15/92, the NRC approved this change, but it was not recorded in the plant's CMD records. Id. at 3,4. Therefore, during 1R5, when testing of SI-8981 was required under the new program, it was not clear during review of results that SI-8981 was fully stroked. PG&E attributed the root cause of this event to personnel error/programmatic deficiency. "Not enough guidance was provided processing commitments of the IST program." Id. at 6.

104- PG&E submitted LER 1-92-001-00 on 4/30/92, after PG&E determined that testing of volume control tank outlet check valve CVCS-8440, Units 1 and 2, were in violation of TS 4.0.5. MFP Exhibit 13 at 1. This check valve performs a safety function as a boundary valve during post-LOCA recirculation. Therefore, it should have been included in the DCNPP IST program and tested periodically in accordance with ASME section XI. Up until 4/1/92, this valve was considered to be non safety-related. Id. The root cause for the exclusion of CVCS-8440 from the IST program was that neither the industry nor Westinghouse had previously identified the safety function of this valve. MFP Exhibit 13 at 6.

105- On 7/6/93, PG&E reported to the NRC that the SI pump discharge check valves 1-8922A, 1-8922B, 2-8922A, and 2-8922B should have been included in the IST program plan. LER 84-047 (7/26/93), MFP Exhibit 7. The root causes of this event included "deficiencies in the scope of the IST program plan review, miscommunication, and personnel error. Id. at 6. See discussion in General Findings regarding Inadequate/Improper Surveillance.

106- Between 1990 and 1993, PG&E has identified thirteen check valves that should have been tested in a closed position under the IST program. These valves had not been fully tested since the plant began operating. In one instance, the problem was compounded when PG&E committed to add a new valve to the program, and then failed to document the new requirement. <u>See</u> discussion above. Thus, as a result of PG&E's errors in assuring the comprehensive testing of check valves, DCNPP operated for years without adequate assurance that these valves were operable and could be relied on for their safety function.

107- Moreover, the Board finds that the incidents described above establish a steady pattern in which PG&E continues to find new check valves which should have been included in the original IST program. This pattern precludes us from finding reasonable assurance that PG&E has made a comprehensive identification of all of the check valves for which full testing is required.

CABLE FAILURES

MFP Exhibit 14: NCR DC1-93-EM-N010 D3 (7/28/93)
MFP Exhibit 15: LER 1-93-005-00 (4/27/93)
MFP Exhibit 16: The Okonite Company Engineering Report #463 (2/5/90)
MFP Exhibit 17: NCR DC1-92-EM-N054 (3/12/93)
MFP Exhibit 18: Results of Analytical Investigations to Determine the Root Causes of Medium Voltage Cable Failures at Diablo Canyon Power Plant, 2nd Draft (5/21/93), Customer Energy Services Business Unit and General Services Business Unit
MFP Exhibit 19: Region V Morning Report (2/17/93)
MFP Exhibit 20: PG&E's OSRG November 1992 monthly report
MFP Exhibit 21: Altran Materials Engineering Review Draft (5/6/93)
PG&E Exhibit 21: PG&E's OSRG February 1993 monthly report

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NRC Testimony pages: 9-10
PG&E Testimony pages: 108-110

108- Between October 1989 and March 1993, DCNPP has experienced five medium voltage cable failures. The first three failures were on 4kV cable which provide power to safety-related auxiliary salt water (ASW) pumps and bus feeder circuits. The last two failures were on 12kV cable which power large condenser cooling water pump motors. They occurred less than six weeks apart in February and March of 1993.

109- The cables were all manufactured by Okonite in 1972 and were installed in 1974. They have been in service since 1984. They are insulated with black ethylene-propylene-rubber (EPR) and jacketed with neoprene. Results of Analytical Investigations to Determine the Root Causes of Medium Voltage Cable Failures at Diablo Canyon Power Plant, 2nd Draft

(5/21/93), Customer Energy Services Business Unit and General Services Business Unit, MFP Exhibit 18 at 4,6.

110- All of the cables originate at the switch-gear, located in the turbine building, and terminate at the cooling water intake structure. Id. They are routed in two separate sets of duct bank conduits, one for each unit, between the turbine building and the intake structure. LER 1-93-005-00 (4/27/93), MFP Exhibit 15 at 3. These duct bank conduits are buried in sand and are covered by concrete. Concrete vaults are located at various intervals to serve as pull boxes for the circuits. The pull boxes immediately outside of the turbine building have drains which are routed to common sump vaults for Units 1 and 2. These are equipped with sump pumps. The Unit 1 and Unit 2 trenches are similar, but the design makes the Unit 1 section of cable conduits near the turbine building susceptible to submergence if the pull box sump pumps are not functional and if the water within the pull boxes rises above the conduit openings. Id. The Start-up Feeder cable pull box, the pull boxes associated with the circuits to the intake structure, and the diesel fuel oil piping trench, all drain into this common sump. NCR DC1-93-EM-N010 D3 (7/28/93), MFP Exhibit 14 at 13. (See also Specific Findings regarding Corrosion of ASW Annubar, DFO and CO2 Piping; it also involves problems with standing water in the trench.) A PG&E investigation determined that water had accumulated in the pull boxes as a result of the pull box drain systems and associated sump pumps not being functional for "a number of years preceding the cable failure events, (i.e. since 1987)." Id. at 14.

111- Laboratory analyses have established that the 12kV cable failure mechanism was chemical attack. PG&E has not been able to determine the cause of the 4kV cable failure. MFP Exhibit 15 at 2.

**112- Finding: PG&E's maintenance and surveillance program was not adequate to detect the degradation of the medium voltage cable.**

113- PG&E testified that two of the cable failures - one in the 12kV and one in the 4kV cable - were identified by testing. Tr. at 652. This means that the other cable failures occurred while the equipment was in service, and thus were not detected through surveillance and testing.

114- The fact that the three of the cable failures occurred during operation and were not detected by testing and surveillance is a matter of concern in that the degradation of the 12kV cable was extensive. The faulted cable was described as "not degraded at the pull box ends, then both ends exhibited approximately 80 feet of 'mushy' jacket material, and then there was approximately 200 feet of cable in the center portion of the run that had no jacket at all. The fault was in the section of the cable that did not have any jacket present..." MFP Exhibit 14 at 25,26. The vendor (Okonite) described the degradation as "unprecedented and has not been seen by the industry previously." Region V Morning Report (2/17/93), MFP Exhibit 19. While PG&E cannot be expected to detect all equipment problems in advance, we find that degradation of this magnitude should have been detected by PG&E's maintenance and surveillance program before the cable failed.

**115- Finding: PG&E has not identified the root cause of the three 4kV cable failures and cannot justifiably claim that they are random occurrences.**

116- PG&E claims that the three safety-related 4kV cable failures "were random in nature and time of occurrence." PG&E Ts. at 108. According to PG&E, it is a "possibility" that "these may just be isolated point failures that occurred and we may never see one of these again." Tr. at 656. PG&E does not "think there's an imminent problem with this cable" or "that there's a generic issue of why that happens..." Tr. at 657. However, despite PG&E's "extensive investigations" and "extensive tests" of the 4kV failures, PG&E has "not been able to determine a root cause." Tr. at 625. Without an understanding of the root cause of the cable failures, PG&E has no credible ground for asserting that the 4kV cable failures were random in nature. Indeed, as noted in PG&E's own study of the problem, "the next cable failure can not be predicted." MFP Exhibit 18 at 15.

117- PG&E has testified that the 4kV cable is used in other safety applications in the plant, some of them in a harsh environment. Tr. at 656-657. Given the fact that there have been three failures of the 4kV cable already, and given the fact that PG&E does not know what caused these failures, the Board finds that PG&E has not provided a reasonable assurance that these cables will not fail again. While the three cable failures that have already occurred may not have affected the immediate safety of the plant, failure of the 4kV in another safety related application could create an immediate safety hazard.

118- In failing to find the root cause of the 4kV cable failure, PG&E has been unable to rule out the possibility that they are susceptible to common cause or common mode failure, in which two redundant trains of 4kV cable might fail at the same time. This would violate the Single Failure Criterion and sharply raise the safety risk to the public. Because of the manner in which PG&E has maintained these cables, we cannot find that PG&E has met its burden of demonstrating that the public health and safety is protected.

**119- Finding: Although PG&E has replaced portions of the 4kV and 12kV cables, they were replaced with the same construction material. This was an inadequate corrective response because there is some question as to the acceptability of this material for the conditions under which it is operating.**

120- In its written testimony, PG&E states: "After failures occurred to the 4kV and 12kV cables, the failed cable sections were replaced. Reviews of the original design, installation, quality assurance and/or quality control audits for the failed cables were conducted. These reviews have concluded that the installed cables are of acceptable quality and design for their specific applications and service conditions (wet or dry)." PG&E Ts. at 110. Thus, PG&E replaced the failed cable sections "with similar construction cable." Tr. at 643.

121- After the 4kV cable failure in Unit 2 in 1989, Okonite evaluated the cable and prepared Engineering Report No. 463 on 2/5/90. (MFP Exhibit 16). In its summary and recommendations, the report stated, in part:

> Since the cable of 1972 in the 'as new' state was not up to standards of performance in terms of testing, moisture stability and dielectric strength of current cables, nor were the methods of production in 1972 as reliable as today's production methods; we feel it would be prudent to replace the medium voltage cables known to be in areas subject to water submergence under normal conditions with cables of today's production methods, materials, and design. MFP Exhibit 16 at 6.

122- A draft report prepared by Altran Materials Engineering on 5/6/93 (MFP Exhibit 21), also noted the vulnerability of the cable jacket material to moisture.

> Cable jacketing materials were considered in detail from the basis of the degraded neoprene and the Hypalon used for the most recent cable replacement applications. Neoprene is a chlorinated polyethylene polymer which has enjoyed a long history of application to class 1E cables. It is generally not used for underground power cable applications though, due, in part, to its long-term instability in water immersion applications. This material is well documented as suffering a significant degree of swelling when exposed to moisture for long periods. Swelling increases it susceptibility to chemical attack and increases its moisture permeability

> rate. Hypalon, which is chlorosulfonated polyethylene, is quite similar to Neoprene in its response to chemical and moisture exposure, but offers some improvement in mechanical properties. It, too, is prone to swelling following long-term moisture exposure. The use of neoprene or Hypalon jacketing materials is not what we would suggest. Instead, the cables should be protected with a lead moisture barrier with an overall linear low density polyethylene (LLDPE) jacket. If this cannot be accommodated... an LLDPE jacket should be used in place of the Hypalon. Careful monitoring of the installed, Hypalon jacketed cables through the next outage is suggested. MFP Exhibit 21 at 3,4.

123- Even PG&E's own nonconformance report notes that: "The cable design and application has been reviewed and determined to be adequate for the assumed environment. The assumed environment was expected to be dry with occasional short-term submergence. However, based on the documented extended submergence conditions experienced at DCPP, a neoprene jacket may not be the best selection." MFP Exhibit 14 at 12.

124- Ignoring these conclusions by the vendor, PG&E's consultant, and PG&E itself, PG&E "used the same cable that was specified in our design as a replacement cable." Tr. at 651.

125- The Board finds that, in light of (a) the five failures in three years of this cable under submerged conditions, and (b) the recommendations of the vendor and consultant, and (c) PG&E's inability to find a root cause for the cable failures, PG&E's decision to use similar construction material as replacement cable in the face of such information indicates a serious deficiency in the maintenance and surveillance program at DCNPP. Not only was the decision to use the same cable as a replacement irrational and unfounded, but it also perpetuates an unsafe situation in which the reliability of the safety-grade 4kV cable is in serious question.

**126- Finding: PG&E was slow to take action in the eventual replacement of this medium voltage cable.**

127- Since 1990, when PG&E received the first recommendation "to replace its medium voltage cables known to be in areas subject to water submergence" (MFP Exhibit 16 at 6), four failures of submerged cables have subsequently taken place at DCNPP. The Board finds this delay untimely and unacceptable.

**128- Finding: Despite five medium voltage cable failures and the replacement of portions of the cable, PG&E has not improved its monitoring system.**

129- The report of PG&E's internal root cause investigation of the cable failures, recommendations were made for improving PG&E's monitoring system:

> To prevent a future chemical attack and to assure the cable systems reliability, the cables and their environments should be accessed and monitored. A cable, ideally energized, might be installed in a spare conduit and removed after five years for examination and testing. Thermal sensors could also be installed at strategic locations and monitored periodically. In addition, the enclosures or pullboxes environmental affects could be monitored by simply placing a easily retrievable, unbreakable, clear container with several samples of the jacket materials in it... MFP Exhibit 18 at 15.

130- Despite these suggestions and the history of its cable failures, however, PG&E, testified that "We have not changed our current methods..." of monitoring the cables. Tr. at 657. The Board finds that, especially in light of PG&E's inability to identify the root cause of these failures, PG&E's failure to improve its monitoring system is unacceptable.

**131- Finding: PG&E's maintenance of the sump pumps was non-existent. This resulted in the submergence of the 4kV and 12kV cables for extended periods of time. This further resulted in the failures of the 12kV cables and may have contributed to the 4kV cable failures.**

132- PG&E admits that the sump pumps that are provided in the vaults "were not at that time part of the formal maintenance program and, accordingly, were not maintained in an adequate manner. After rains, the vaults would fill with water and flood the conduits." PG&E Ts. at 110.

133- PG&E notes that the "failures which occurred in the 12kV nonsafety-related cables were caused by exposure to a contaminant which was present in the underground conduits..." PG&E Ts. at 109. PG&E further notes that "a contributory cause of the 12kV failures was believed to be water carrying contaminants into the cable conduits." PG&E Ts. at 110. "The water was the medium that carried the contaminate to the 12kV cables." Tr. at 649,650. "12kV had a submergence problem." Tr. at 646.

134- Regarding the 4kV cables, however, PG&E argues that "they may have been submerged in water for some period of time. But all of our investigation showed that there was no indication of any water intrusion into the installation. So, we don't see that as being a problem." Tr. at 647. "We don't believe that the fact that the sump pumps didn't work was a problem for the 4kV..." Tr. at 662. However, PG&E has yet to establish the root cause for the 4kV cables. Hence, PG&E cannot justifiably claim that submergence was not an issue for the 4kV cable failures.

**135- Finding: PG&E's corrective action to maintain the sump pumps was an untimely response.**

136- PG&E admits that the sump pumps were inoperable for "a period of time preceding the cable failure events..." MFP Exhibit 15 at 7. "Both Unit 1 & 2 common pull box sump pump systems were not adequately maintained, and had been out of service for a number of years (i.e. since 1987)." MFP Exhibit 14 at 14. The first cable failure occurred in 1989 and the cables were found submerged in water. Id. at 24. Yet, no preventive maintenance was established for the cable vaults and the sump pumps until the issuance of NCR DC1-EM-N054 (MFP Exhibit 17) after the occurrence of the fifth cable failure in 1993.

137- NRC had already cautioned PG&E about age/environment induced electrical cable failures in NRC Information Notice (IN) 86-49. See MFP Exhibit 14 at 26. As addressed in the

IN, on 11/21/85, San Onofre Unit 1 experienced a loss of offsite power when a transformer was tripped by its differential relays because of a failed cable to the class 1E 4160-V bus. The most likely cause of the cable failure was determined to be temperature-induced accelerated aging and degradation of the cable insulation. The notice stated "another important facet of the periodic maintenance and testing program for cable circuits is the walkdown inspection to identify actual or potential environmental conditions (heat, water, chemicals, etc.) in the immediate vicinity of the cables that could adversely affect cable conditions." (emphasis added).

138- PG&E's response to this notice was that its class 1E cables are run inside rigid iron conduits and routed away from high temperature piping and equipment. MFP Exhibit 17 at 26 and Tr. at 641. The Board notes that PG&E made no response to the other potential environmental conditions such as water or chemical intrusion.

139- The Board concludes that PG&E's response to the inoperable sump pumps and the extended submersion of the cables was untimely and irresponsible. Furthermore, the problem with the design of the Unit 1 section of cable conduits near the turbine building which makes it more susceptible to submergence (MFP Exhibit 15 at 3) has yet to be rectified.

**140- Finding: Five medium voltage cable failures in three years represents a significant safety issue.**

141- The two 12kV cable failures were nonsafety-related. Two of the three 4kV cable failures were safety-related. PG&E Ts. at 108,109. The NRC concluded that "plant safety had not been significantly reduced by these cable failures, due to the presence of other, unaffected cables for redundant safety-related pumps." NRC Ts. at 10. PG&E concurred. MFP Exhibit 15 at 11.

142- This analysis misses the point that redundancy is <u>required</u> for safety-related components by the Single Failure Criterion in 10 C.F.R. Part 50, Appendix A. The purpose of PG&E's maintenance and surveillance program should be to ensure that both trains of a safety system are functioning, so that if one train fails during an accident, the other one is available to back it up. Thus, it is unacceptable to argue that the failure of one train of a safety system due to inadequate maintenance by PG&E is acceptable because the backup train is still functioning. Moreover, as discussed above, the 4kV cable has safety applications elsewhere in the plant, including a harsh accident environment. The facts that (a) the 4kV cable has experienced multiple failures, and (b) PG&E still does not know the root cause for these failures, raise the concern that all of the 4kV cable is flawed in some unknown respect and therefore cannot be relied upon with a reasonable degree of confidence. Moreover, a flaw in all of the 4kV cable would render it susceptible to common cause or common mode failure, i.e., a failure mode in which both trains of a safety system fail during an accident. We are particularly concerned about the vulnerability of 4kV cable located in a harsh environment. We find that, under the circumstances, there is an unacceptable risk that the added stress of accident conditions could lead to failure of one or both trains of 4kV cable which supplies an essential safety system.

143- In conclusion, the Board finds that the series of events that occurred during the time frame from 1989 through 1993 and the actions that were and were not taken are significant. They illustrate that PG&E's maintenance and surveillance program at DCNPP:

1. was inadequate to identify the degradation of the cables until they failed.
2. failed to maintain the sump pumps and prevent the submergence of these cables.
3. responded to the maintenance of the sump pumps in an untimely fashion.
4. responded with the replacement of the cables in an untimely fashion.
5. was unable to determine the root cause of the 4kV cable failures.
6. inappropriately replaced the cables with material of similar construction.

7. has not improved its cable monitoring system.

(See also Untimely or Ineffective Response to Maintenance Problems in the General Findings.)

WRONG SIZE MOTOR INSTALLED

MFP Exhibit 24: NCR DC2-93-EM-N031 (7/28/93)

Transcript pages: 689-694

144- During 2R5, a 10 ft-lb motor was installed on motor operated valve (MOV) DI-2-8974A rather than the required 15 ft-lb model. NCR DC2-93-EM-N031 (7/28/93), MFP 24 Exhibit at 3. This safety-related motor is required to close the MOV during switchover from injection phase to cold leg recirculation phase. Id. at 1.

145- This event was caused by several personnel errors:

1. The initial personnel error was caused during work order development when the work planner misread page 4 of the DCN.
2. During his self-verification process, the electrician failed to identify that the wrong motor was installed.
3. The QC inspection hold point was performed incorrectly. The inspector misread the motor name plate.
4. The DCN sponsor did not identify that the wrong motor had been installed.

Id. 2,3.

**146- Finding: The barriers designed to prevent errors like the one described above were ineffective, due to multiple personnel errors. Such a multiplicity of errors, all involved in verifying the accuracy of the same job, is evidence of a programmatic deficiency in training at DCNPP.**

147- This incident was initially caused by a personnel error in that the "work planner" misread a DCN during work order development. Id. at 4. By itself, such an error might be found to have little significance. The problem here is that not less than three other individuals, who were responsible for checking the correctness of the installation of the motor, failed to identify the fact that the wrong one had been installed. The occurrence of three consecutive personnel errors in verifying the proper installation of the same piece of equipment can hardly be deemed an "isolated personnel error" which is "inherently tolerate[d]" by plant design and testing features. PG&E proposed findings M-A21 and M-A22. To the contrary, we find this to be an indicator of a programmatic deficiency in PG&E's maintenance and surveillance program. While training is suspect, at this point we do not know what is the cause of the problem. In any event, the occurrence of this event prevents us from finding that DCNPP maintenance personnel are capable of doing their job in an adequate and safe manner. See also a discussion of Breakdown of Multiple Barriers in the General Findings.

**148- Finding: The installation of the wrong motor had safety significance.**

149- PG&E argues, both in its NCR and in its proposed findings, that the installation of the wrong valve motor had no safety significance. MFP Exhibit 24 at 4, PG&E proposed finding M-A20. We find PG&E's safety analysis to be incorrect. Moreover, as discussed with respect to numerous other safety issues raised in connection with these proposed findings, PG&E's safety analyses of its maintenance problems reflects either a misunderstanding of or a poor attitude toward the significance of safety issues and the role of maintenance in protecting the safety of the public. See also Inadequate and Incorrect Analyses of Safety Significance in the General Findings.

150- PG&E makes two principal arguments in support of its claim that the installation of the wrong motor had no safety significance in this case. First, it states that the associated valve could have been closed manually. MFP Exhibit 24 at 4. However, as PG&E itself concedes, there is no procedure for closing the valve or its companion. Id. Moreover, under the worst case conditions, in a large break LOCA, the operators would have only 13 minutes to close the valve. The closing of the valve in such a short period would be a marginal, if not unlikely, proposition.

151- Second, PG&E argues that the capability of the 10 ft-lb motor at the design basis voltage of 85% is 104 ft-lb.

This equates to 8194 lb of thrust at the worst stem factor. This is more than adequate to fully shut the valve under design basis condition (7996 lbs is calculated under ICE-12 evaluation). Id. at 5. However, this leaves a margin of error of only 198 pounds, or less than 3% of the worst case calculated thrust for a design basis accident. Such a narrow margin of error gives no cause for comfort, especially in light of the fact that the design requirements are based on calculations and thus may vary somewhat from actual accident conditions. In this regard, we take judicial notice of the fact that the NRC recently warned licensees that diagnostic equipment used to calculate stem thrust may be inaccurate and may yield nonconservative results. NRC Generic Letter 89-10, Supplement 5, "Inaccuracy of Motor-Operated Valve Diagnostic Equipment" (June 28, 1993).

STORAGE AND HANDLING OF LUBRICANTS

MFP Exhibit 27: NCR DCO-93-MF-N039 (7/27/93)
MFP Exhibit 28: NCR DCO-91-MM-N061 (10/25/91)

Transcript pages: 726-745

152- PG&E has a history of failing to comply with its procedures to control lubricants (AP D-753). These discrepancies include: unlabelled and mislabelled grease guns and oil pumps; cross contamination of greases and oils; the use of wrong oils; and failure to maintain log books. NCR

DCO-93-MF-N039 (7/27/93) MFP Exhibit 27; NCR DCO-91-MM-N061 (10/25/91) MFP Exhibit 28.

153- This issue was first identified in 1987, and the NRC issued a notice of violation at that time. MFP Exhibit 27 at 10. Additional problems were found in 1991. MFP Exhibit 28. Despite corrective measures purportedly taken by PG&E, similar problems occurred in 1993. MFP Exhibit 27.

**History of Noncompliance**

154- PG&E's history of failure to comply with AP D-753 (control of lubricants) includes the following events:

155- On March 26, 1987, the NRC issued a notice of violation to DCNPP for failure to comply with AP D-753. See MFP Exhibit 28 at 2. A one gallon unlabelled container filled with oil was in the tool shed area of the intake structure, another gallon unlabelled container filled with oil was in a storage cabinet in the new cold machine shop, and three unlabelled grease guns were found in the hot machine shop tool room. The log books were not being maintained in the bulk storage areas or at any of the dispensing rooms. Id.

156- PG&E discovered that on April 10, 1990, "the wrong oil, GST-32, was added to the heater 2 drain tank pump 2-1. The required oil should have been GST-68." Id.

157- On November 3, 1991, "the wrong oil (GST-32)" was added to the CCWP 2-1 motor bearing. Again, the required oil was GST-68. Id. at 3.

158- On July 12, 1991, PG&E wrote NCR DCO-91-MM-N061 (a later revision of this NCR is MFP Exhibit 28) to "identify discrepancies noted in lubrication storage and handling." MFP Exhibit 27 at 3. These discrepancies included the following:

1. A Lincoln model-1035 grease gun had a brass tag attached indicating "Exxon EPO EQ" type grease. Installed in the gun was a cartridge of "Chevron Dura-Lith grease EP-2." MFP Exhibit 28 at 2.

2. Upon visual inspection of the one hand pump for 35 pound grease cans, PG&E found that the pick-up tube for the pump "contained 3 different colors of grease mixed together." This pick-up tube "can hold approximately 40 ounces of grease." The pump is used for multiple types of greases without clearance of the pick-up tube. Id.

3. Two Hi pressure grease guns "were not marked with the type of grease installed as required by AP D-753." Id.

4. Inspection of the hand oil pump for 55 gallons barrels determined that approximately one cup of oil remained in the pump. According to PG&E, although this amount of oil is "insignificant" when large quantities of oil are dispensed, "when smaller quantities are needed (i.e., a pint), "mixing of incompatible lubricants could result." Id.

5. Grease guns are typically marked as containing "EP-2." However, there are various types of EP-2 such as Duralith, Polyurea, moly and Ultra Duty. Thus, PG&E

found that the grease guns should be marked with the specific type of EP-2. Id. at 3.

6. An obsolete revision (#17) of AP D-753 was found in the lubricants storage room. The correct revision was 18. Id.

159- The Auxiliary Salt Water ("ASW") pumps are lubricated with AW Machine-100 oil. Exhibit 27 at 3. On June 22 and 23, 1993, during maintenance on the ASW pumps, PG&E discovered that an incompatible oil, GST-32, had been added to the bearing oil reservoirs for the upper and lower bearings of the ASW 1-1 pump motor. Id. A sample showed that the oil on the bearings was primarily AW-100, with about 10% GST-32. Id. at 4.

160- PG&E checked ASW 1-1 and 1-2 pump motors for contaminated oil on June 22 and 23. Id. However, PG&E waited a whole month to check the oil in the ASW pump motors in Unit 2. The oil in those pumps was also discovered to be contaminated, although the NCR prepared by PG&E does not describe the extent of the contamination. Id.

161- PG&E still does not know how the wrong oil got into the pump motors. Tr. at 728. The problem was discovered when a gallon container with a half gallon of GST-32 oil was found in the intake storage area in Unit 1. MFP Exhibit 27 at 3. However, the oil log book did not reveal where or when this oil was obtained. Id. PG&E also testified that it was improper to leave an oil container in the intake area; "it should have been used once and then disposed of." Tr. at 742.

**162- Finding: Failure to control lubricants is a recurrent problem at DCNPP and demonstrates a deficient maintenance and surveillance program.**

163- In NCR DCO-91-MM-N061, PG&E attempted to determine the causes of its problems with lubricants and to correct the problem. PG&E found that the storage and handling of lubricants was difficult to control due to "lack of specific ownership" of the lubricants storage room. MFP Exhibit 28 at 5. "Accessibility to lubricants is shared with other departments. These conditions provide opportunity for lubrication procedure violations." MFP Exhibit 28 at 10. Contributing factors identified by PG&E include that identification of lubricants was unclear and lacked uniformity; that dispensing mechanisms were not clearly identified; and that personnel were inattentive tc details. MFP Exhibit 28 at 5. In response, PG&E appointed a foreman to oversee the lubricant storage area; provided for an additionally monthly audit of the area; and committed to "enhance and standardize the markings on the grease-dispensing tools." Id. at 7,8. PG&E also testified that it "did a lot of training with the operations personnel." Tr. at 738.

164- PG&E's reforms were ineffective to prevent the misuse of oil on the ASW pumps in 1993. As Maintenance Manager Bryant Giffin testified,

> We thought that we had a handle on it and that posting the procedure and having the rules posted and giving

training to those people that use oils would have resolved this, but it, apparently, didn't. Tr. at 734.

According to Mr. Giffin, PG&E is still evaluating the 1993 incident and how to respond to it. Id. PG&E is considering changing from the current "honor system" to providing a position that would be responsible for distribution of lubricants. Tr. at 732. However, such a change has not been implemented. Tr. at 742. Moreover, PG&E has noted the potential negative consequences of restricting access to lubricants. Tr. at 737.

165- The Board finds that PG&E has a recurrent problem in ensuring the correct use of lubricants at the DCNPP. We note that the incidents described above are not the only ones: an incorrect lubricant was also found in containment isolation valve 2-FCV-37 in March of 1993. (See Limitorque 2-FCV-37 Failed to Close in the Specific Findings.) This problem has a bearing on the safety of the plant, because the use of incorrect lubricants can increase the wear on safety equipment, MFP Exhibit 27 at 8, and thus may affect its reliability. We note that, although in the case of the ASW pumps, the amount of contamination was minimal, the potential exists for greater contamination with more serious effects. See MFP Exhibit 28 at 2 (presence of oil in pump deemed "insignificant" when large quantities of oil are being dispensed, but could result in "mixing of incompatible lubricants" when smaller quantities are involved).

166- PG&E is still in the process of identifying the cause of the most recent incident involving misuse of lubricants, and is still evaluating corrective actions. The Board is concerned that PG&E's previous attempts to resolve the problems with misuse of lubricants have been unsuccessful; and that PG&E has not identified the reasons that these corrective actions were unsuccessful. Under these circumstances, in which the causes of PG&E's problems have not been identified or resolved, we cannot find that PG&E's program for the safe and appropriate handling and use of lubricants is adequate to protect the public health and safety.

FUEL HANDLING BUILDING

MFP Exhibit 38: NCR DC1-91-TN-N007 (12/11/91)
MFP Exhibit 39: LER-89-019-00-01 ((9/19/91)
MFP Exhibit 41: OSRG November 1991 Monthly Summary

Transcript pages: 777-828
PG&E Testimony: 104,10

167- In order to assure that all potential releases from the spent fuel pool are exhausted through the Fuel Handling Building (FHB) exhaust filters, the fuel pool area must be maintained at a negative pressure. LER-89-019-00-01 ((9/19/91), MFP Exhibit 39 at 4. On 1/18/91, PG&E declared the FHB ventilation system inoperable because the system failed to maintain a negative 1/8" water gauge pressure in the building, as prescribed by the plant's technical specifications. This situation was discovered during the scheduled 18-month STP (M-41). Because no changes were made which would have impacted the FHB ventilation system subsequent to the performance of the last successful STP on 9/18/89, PG&E concluded that the FHB ventilation system had "most likely" been inoperable during fuel movement which took place during the 1R3 on 10/15/89. Fuel movement and activity over the spent fuel pool were suspended. Id. at 2,3. NCR DC1-91-TN-N007 (12/11/91), MFP Exhibit 38 at 2.

168- PG&E attributed the root cause to degradation of the FHB sealing material. This degradation included:

1. gaps between sections of sheet metal siding;
2. unsealed piping penetrations;
3. missing or degraded door and piping seals;
4. gaps between the FHB movable crane wall and the FHB fixed walls; and
5. through wall oxidation of FHB sheet metal siding.

MFP Exhibit 38 at 11,12.

169- Contributory causes included:

1. reduced flow through the FHB exhaust fans due to accumulation of dirt in the ducts;
2. failure to maintain a 19.8% difference between the supply and exhaust flows as required by the FSAR;
3. blocking of a FHB exhaust duct by plastic sheeting.

Id. at 13.

**170- Finding: No preventive maintenance procedure exists for the fuel handling building or its sealing capabilities. The absence of such a procedure resulted in the degradation of the sealing capabilities to such an extent that the fuel handling ventilation system failed to meet TS requirements.**

171- PG&E has acknowledged that although "PMs exist for the FHB doors" and "STPs exist for monitoring the ventilation system components," a "PM program for the building or its sealing capabilities does not exist." Id. at 8,9. A PG&E witness noted that the building sealing "got old and as it got old it degraded... And you combat aging by monitoring and testing and replacing and painting and taking care of it." But, "No, I did not have a PM program for the building." Tr. at 807,808 (Giffin).

172- The Board finds that, contrary to PG&E witness Giffin's assertion, PG&E did **not** "monitor and test" the building or its sealing capabilities. Rather, the degradation of the sealing capabilities was discovered by PG&E only after the problem became so severe that the building failed to meet TS requirements. Furthermore, "several larger gaps in the FHB ventilation boundary were noted that have existed since the performance of the last STP, including seals around CST piping and between the fixed and movable walls in the FHB. MFP Exhibit 38 at 6,7. We conclude that PG&E's failure to institute a procedure for maintaining the building or its sealing capabilities constitutes a deficiency in its maintenance and surveillance program. <u>See also</u> discussion in General Findings regarding Detection and Correction of Aging Effects.

**173- Finding: The exhaust fan was insufficiently maintained and contributed to the failure of the FHB to maintain its required negative pressure.**

174- As discussed above, a contributory cause of this incident was reduced flow through the FHB exhaust fans due to accumulated dirt. In its NCR on this event, PG&E notes that "NOS trending of the exhaust flows from the FHB had noted a continual decline in exhaust flow volume. This decline amounted to approximately 10% capacity in 15 years." MFP Exhibit 38 at 6.

175- After the FHB was declared inoperable, PG&E discovered a reduced flow through the FHB exhaust fans due to accumulation of dirt in the ducts and a FHB exhaust duct that was blocked by plastic sheeting. PG&E found that these factors had contributed to the failure of the FHB to maintain its negative pressure. MFP Exhibit 38 at 13.

176- The NOS trending results reasonably should have prompted PG&E's maintenance and surveillance team to examine the exhaust system. Instead, PG&E ignored this indication until the system failed to meet TS requirements. Only then did not notice the dirt and the plastic sheeting on the fan. Accordingly, we find that PG&E's poor maintenance of the exhaust fan was an unnecessary and unacceptable causative factor of the loss of pressure in the FHB, and demonstrates an insufficiency in PG&E's maintenance and surveillance program at DCNPP.

177- **Finding: PG&E's maintenance and surveillance program was not adequate to monitor the negative pressure of the FHB before it failed to meet TS requirements.**

178- PG&E claims that "past surveillance test data did not indicate a trend in maintaining the required negative pressure of the FHB." Id. at 12. Yet, at the same time, PG&E concedes that

> The lack of an adverse trend in the FHB pressure may not have been identified because several variables affecting the results of the test, such as test performer, weather conditions, door position, and instrument inaccuracies, were not consistent during the three tests. MFP Exhibit 38 at 12.

PG&E's listing of these four significant "variables," including "instrument accuracies," raise serious doubts as to whether PG&E's testing methods are at all accurate. We find that the existence of such variables, without additional explanation by PG&E - including the margin of error of the test - fundamentally undermines the reliability of PG&E's program for maintaining adequate negative pressure in the FHB.

179- Moreover, the Board finds that PG&E failed to respond in an adequate or responsible manner when it tested the FHB pressure in 1989 and found it to be .15 inches - within .025 inches of the limit specified by the plant technical specifications (1/8" or .125"). Given the acknowledged "variations" in the tests, PG&E never should have accepted such a slim margin of error. Instead, PG&E rejected two requests, based on the "low margin" of the test result, to "reduce the building supply flow to provide a greater margin for the surveillance test," on the ground that "the action was not necessary because the building had always passed the surveillance test in the past, and past data did not indicate a negative trend in maintaining the required negative pressure." Id. at 12. Thus, PG&E ignored a pressure reading that was perilously close to the TS limit, based on questionable test results from the past. As discussed above, PG&E also ignored the NOS trending which had showed a continuous decline in exhaust flow volume. The Board finds this to be an example of unsound judgment and poor performance in maintaining the DCNPP.

180- The Board notes that, in an effort to ensure that adequate negative pressure is maintained during fuel movements, PG&E now performs the pressure test within seven days of any fuel movement. MFP Exhibit 38 at 18. However, we find this to be an inadequate response to the problem, because PG&E still has not addressed the variability of the test results. Thus, we are unable to find either that the tests will yield meaningful results in light of the variations in "test performers" and "instrument accuracies," or that seven days is a short enough interval between the test and the fuel movement in light of the variations in plant and weather conditions which may affect the result.

**181- Finding: PG&E's maintenance and surveillance program was not attentive to the upkeep of the FHB.**

182- PG&E reported in its NCR that "during startup for the FHB, fasteners for the siding near the crane rail were tightened regularly. This practice ceased after the building was turned over to the plant, as it was never communicated that a problem with the fasteners existed." MFP Exhibit 38 at 5. Additionally, the "original design drawings for the FHB included an inflatable seal for the movable wall. The seal is no longer installed, and a DCN search did not identify any time that the seal was removed." Id. at 8.

183- PG&E's OSRG November 1991 monthly summary, reported that

> long term action has not been effective in restoring either FHB to operable status due to additional problems encountered. Door labeling control was not effective since the NRC, on follow-up, discovered doors open and labels missing. In addition, all corrective actions should have been completed prior to 1R4, but were not. OSRG November 1991 Monthly Summary, MFP Exhibit 41 at 5.

184- Accordingly, the Board finds that the untightened fasteners, the missing inflatable seal, and the careless control of doors indicate a lack of thoroughness and attention to detail in PG&E's maintenance and surveillance program. See discussions in General Findings regarding Untimely Detection and Correction of Aging Effects.

CONTAINMENT PERSONNEL AIRLOCK

MFP Exhibit 42: NCR DC2-93-WP-N025 (6/23/93)5/19/93)
MFP Exhibit 43: LER 2-90-011-00 (5/26/93)
MFP Exhibit 44: LER 1-91-016-00 (10/28/91)

Transcript pages: 828-854

**1991:**

185- On 6/11/91, the plant's technical specifications were not met when the conditional surveillance for a leak-rate test of the containment personnel airlock door seals was not satisfactorily performed. LER 1-91-016-00 (10/28/91), MFP Exhibit 44 at 1.

186- The containment personnel airlock door seals are required to maintain the pressure integrity of the containment building. Id. at 6. "If they were not operable there would be a safety concern." Tr. at 839. Technical specifications requires that the containment airlock be demonstrated operable after each opening by verifying the seal leakage is acceptable. An automatic leak-rate monitor activates a test cycle after each opening and closing of the airlock doors. MFP Exhibit 44 at 2.

187- On 9/20/91, PG&E had issued a clearance to take the leak-rate monitor out of service for calibration. This clearance closed the air supply valves to the door seals and rendered the system inoperable for either manual or automatic testing. The clearance did not, however, identify that the leak-rate monitor was required to meet TS surveillance requirements. Additionally, because the leak-rate monitor was still energized and in automatic, it appeared that a leak-rate test could be performed. Id. at 3. PG&E did not identify this problem with the leak-rate monitor until 6/5/91. Id. at 4.

188- PG&E determined the root cause of this event to be personnel error caused by inadequate knowledge concerning the operation of the containment personnel hatch leak-rate monitor.

> When queried, the majority of the operators thought that resetting the leak-rate monitor at the local panel would cause the monitor to repeat the door seal test. If personnel had understood that following a leak-rate test failure alarm, it was mandatory to perform a manual leak-rate test, no surveillance would have been missed. Id. at 5.

189- As indicated by plant records, an acceptable leak rate test was not performed following 17 containment entries during the period from 6/5/91 to 9/27/91. Id. at 1.

**190- Finding: PG&E's method for tracking missed technical specification surveillances misleading.**

191- PG&E claims that "over the past ten years" - keeping in mind that they do "over 10,000" surveillances each year - it has missed only 65 surveillances. Tr. at 836. "This refers only to tech spec surveillances." Tr. at 844. The Board finds this characterization misleading. PG&E counts all missed surveillances stemming from the same root cause as only one missed surveillance. For example, with respect to this incident, PG&E testified that

> there were 23 entries into containment (NH) during the period from June 5, 1991, to September 27, 1991... Following 17 of these entries the operators reset the alarm and assumed that because there were no further

alarms the monitor satisfactorily confirmed an acceptable leak rate. Therefore, the personnel airlock door seals were not satisfactorily tested..." MFP Exhibit 44 at 3,4.

According to PG&E's tracking system, these 17 entries in which the personnel airlock door seals were not satisfactorily tested is considered <u>one</u> missed tech spec surveillance. Tr. at 845. Thus, even though a surveillance may be missed many times, with potential safety consequences, it is counted as only one mistake. The Board finds that this very skewed way of counting missed surveillances detracts from the credibility of all of PG&E's general assertions about the adequacy of its surveillance program.

**1993:**

192. In 1993, an event occurred involving containment personnel hatch pressure gauges. Two previous events were also identified. PG&E addressed these three incidents in DC2-93-WP-N025 (6/23/93), MFP Exhibit 42, and LER 2-90-011-00 (5/26/93), MFP Exhibit 43.

193. The containment personnel airlock (PAL) provides access to containment while maintaining a pressure boundary between containment and the outside atmosphere. The gauges are part of the pressure boundary between the atmosphere and the inside of the air lock. Failure of a gauge could result in leakage between the inside of the PAL and containment and/or the atmosphere. MFP Exhibit 42 at 2. Technical specifications requires that an air lock be demonstrated operable prior to establishing containment integrity when

maintenance has been performed on the air lock that could affect the sealing capability. Id. at 3.

194- On 4/25/93, PG&E serviced and replaced containment personnel airlock hatch pressure gauge PI-178. The post-maintenance testing (PMT) section in the work order, however, incorrectly specified "N" and no PMT was performed. Id. at 1.

**195- Finding: Previous events were discovered.**

196- PG&E's investigation into previous occurrences of the event determined that there were two instances of gauge removal (9/20/90 and 9/21/90) in which the components were returned to service without any PMT performed. MFP Exhibit 42 at 4.

**197- Finding: PG&E provided inadequate information to the work planner.**

198- According to PG&E testimony, PG&E initially felt that the cause of the event was due to personnel error, yet "after researching it further it was more of a deficiency with the documentation that was provided to the work planner." Tr. at 830. "The references used by the I&C work planners to prepare the work order, including the component database, did not identify that the tubing and fittings associated with the pressure gauges comprised a containment leakage boundary and that disconnection of the pressure gauges required a leak rate PMT." MFP Exhibit 42 at 7. The work planners "didn't recognize the effect on the pressure boundary." There "should have been a warning in there to alert the planner when he reviewed it..." Tr. at 830.

199- The Licensing Board finds that the repeated occurrence, on three occasions, of missed post-maintenance surveillances for the containment personnel air lock indicates a significant deficiency in the maintenance and surveillance program at DCNPP. The Board is concerned because these events involved inadequate instruction as well as lack of knowledge on the part of personnel.

COMPONENT COOLING WATER (CCW) HEAT EXCHANGER

MFP Exhibit 47: NCR DC2-TS-N017 (6/15/93)

Transcript pages: 856-868

200- The function of the Component Cooling Water (CCW) System is to remove the heat generated by the various plant systems without releasing radioactive material to the environment. NCR DC2-TS-N017 (6/15/93), MFP Exhibit 47 at 2.

201- Each Unit at DCNPP has two YUBA CCW heat exchangers which have 1,237 straight tubes approximately 35 feet long. In March of 1993, during 2R5, eddy current testing was conducted on the tubes on CCW heat exchangers 2-1 and 2-2. Fretting was found on the outside diameter of the tubes at the baffle plates. Tubes with damage greater than 20% were plugged. Ten tubes were identified for plugging on CCW heat exchanger 2-1. Several tubes were plugged on heat exchanger 2-2. Id. at 3,4.

202- According to the NCR for this event,

> Fretting which is also called chatter is the most common form of tube damage. It occurs at support plates or baffles. Tubes may wear either 180 degree or 360 degrees around their circumference. The most common occurrence is the 180 degree wear, is especially found in the bundle periphery. The support plate or baffle may also wear, causing increased hole size. The hole and tube wear increase the clearance between the tube and support plate/baffle. This condition reduces damping and increases the tube vibration. Therefore, rate of fretting degradation increases exponentially. Id. at 5,6.

203- **Finding: Eddy current testing is not being performed with sufficient frequency.**

204- PG&E states that as part of its in-service inspection (ISI) program, it performs tests to identify and predict any degradation on equipment. Tr. at 857. PG&E claims that the CCW heat exchanger tubes had been eddy current tested previously and that the frequency of these tests is based on the expected wear and service life of the heat exchanger. PG&E further asserts that the surveillance for this equipment is sufficient. Tr. at 858. The NCR states that "regularly scheduled Eddy Current testing is designed to detect this condition so it can be corrected before the failure of the tubes." Id. at 6. But the NCR also notes that "1R5 and 2R5 were the first times that the CCW heat exchangers had been eddy current tested." Id. at 13.

205- In light of the extent of the degradation that was identified on the CCW heat exchangers, and the rapid - indeed exponential - rate at which these tubes can degrade, the Licensing Board maintains that PG&E's maintenance and surveillance program is inadequate. The fifth refueling outage, when eddy current tests were first performed, is fully seven or eight years after DCNPP began operation. This is an unacceptable lapse of time to inspect these safety components. We conclude that the surveillance is not being performed with sufficient frequency to detect the degradation of this system. See discussion in General Findings regarding Untimely Detection and Correction of Aging Effects and Inadequate/Improper Surveillance.

**206- Finding: The ability of maintenance and surveillance activities to assure the efficiency of the CCW heat exchangers remains in question.**

207- PG&E determined the root cause of the vibration and the fretting that was found on the tubes to be caused by the increased flow rate when operating two residual heat removal (RHR) heat exchangers and only one CCW heat exchanger. The other heat exchanger is required for miscellaneous maintenance and operational needs. Tr. at 861.

208- PG&E found that a contributory cause of the degradation was the fact that the actual flow is "much greater than original operating conditions (up to 25,000 gpm refueling vs. 12,500 gpm design)." Id. at 5. "With two heat RHR heat exchangers on line, the flow rate through one CCW heat exchanger is 22,000 gpm." Id. at 13. The NCR stated that the

Bechtel report was discussed; it was "the basis for exceeding the original design flow rate." Id.

209- The NCR also notes that the design of its heat exchangers is an old static design rather than the present dynamic design of the modern heat exchangers. Id. at 11.

210- The efficiency of the system with the reduced flow rate is another concern. According to NRC, "there is 2% margin in the heat transfer coefficient. Therefore, 2% of the heat exchanger tubes can be plugged without creating much reduction in efficiency." Id. With the plugging of ten tubes out of 1237 in exchanger 2-1 (MFP Exhibit 47 at 13), the efficiency has dropped by 0.8% - almost half of this margin. The Board is concerned that if PG&E waits a similar interval to conduct the eddy current tests again, this plugging - along with increased leakage during the interval - may bring the already- narrow safety margin down below 2%. We note that the frequency of eddy current testing has not yet been determined. Tr. at 866.

**211- Finding: PG&E's corrective actions, maintenance, and design changes may have violated the original design criteria by improperly exceeding the original design flow rate.**

212- As a corrective action to prevent further degradation, PG&E has stated that it will revise the procedure to incorporate the maximum flow limits on the CCW heat exchangers. MFP Exhibit 47 at 8. PG&E also notes, however, that because there are times when extra cooling is required; perhaps further corrective actions are necessary. Tr. at 864,865. Additionally, PG&E notes as a "prudent action" in the NCR that a method is required for "warning for maximum flow condition that could occur and the resulting damage." Id. at 9.

213- The Licensing Board finds that PG&E is exceeding - or plans to continue to exceed - the maximum flow rates for CCW; thus further degradation can be expected. We also find that PG&E has failed to demonstrate that its maintenance and surveillance program is adequate to detect or compensate for this degradation, because the frequency of the eddy current testing has not yet been determined. Thus, there is no reasonable assurance that degradation will not exceed the safety margin by the time of the next inspection. See discussion regarding Failure or Unreliability of Important Safety Systems in the General Findings.

AUXILIARY BUILDING VENTILATION SYSTEM INOPERABLE

MFP Exhibit 49: NRC DC2-93-MM-N012 (6/11/93)
MFP Exhibit 50: LER 2-93-002 (4/5/93)

Transcript pages: 880-886

214- The primary safety functions of the Auxiliary Building Ventilation System (ABVS) is to (1) maintain the temperature of engineered safety feature (ESF) equipment within acceptable limits and to (2) filter exhausted air to minimize the amount of radiation released during accident conditions. LER 2-93-002 (4/5/93), MFP Exhibit 50 at 2.

215- On 3/4/93, PG&E attempted to perform preventive maintenance on the Unit 2 ABVS. PG&E exceeded the technical specificiations when the ABVS was rendered inoperable by the closure of a manual damper. PG&E filed a Licensee Event Report regarding this incident. (MFP Exhibit 50 at 2) Id.

216- The maintenance work was complicated by a variety of clearances that were established and changed to accommodate other work. Additionally, the work order instructions required the workers to close the manual dampers and was not specific as to which dampers to close. Only dampers MD-5A and MD-5B should have been closed. However, damper MD-3 was closed; this rendered the ABVS inoperable. NCR DC2-MM-N012 (6/11/93), MFP Exhibit 49 at 3-5.

217- PG&E claims that the root cause of the incident was due to two personnel errors. First, the system engineer altered an earlier clearance without complete knowledge of the impact it would have on the system. "If the clearance had not been altered the work in the field could have been performed... without a mishap." MFP Exhibit 49 at 6. PG&E found that a system of checks and balances, intended to preclude such a misjudgment, had failed in this case. Id.

218- Second, PG&E found there was "personnel error resulting from poor communication." Id. The "craftsman did not notify the Mechanical Maintenance Foreman that the

Operations Shift Foreman had only approved the closure of Dampers M-5A and M-5B" and not MD-3, which was erroneously closed. Id.

219- Contributory causes included:

1. Poor drawings: The design drawings associated with the HVAC system are not adequate, especially when used to develop clearances when work involves breaching ducts that cross-communicates with other ducts or plenums.

2. Coordinated clearance weaknesses: The system engineer and the clearance coordination office did not adequately research the Library Clearance in order to identify the conditions of the original clearance.

3. Poor communication: The mechanical maintenance craftsman did not relay to the maintenance foreman all of the information discussed and approved by the shift foreman, i.e. the specific dampers that were to be closed.

4. Inadequate work order: The work order instructions were not specific and required interpretation by the mechanical maintenance personnel. "Had the instructions been clear as to which dampers to close, the event would not have occurred."

MFP Exhibit 49 at 7.

**220- Finding: This incident demonstrates inadequate maintenance instructions and poor communication between**

**maintenance and operations staff creating an unacceptable safety risk.**

221- The Licensing Board finds that this is an example of how inadequate maintenance instructions, combined with poor communications between maintenance and operations personnel, may create dangerous conditions in the DCNPP when complex maintenance tasks are performed during plant operation. Moreover, it is disturbing to note that a system of "checks and balances" or "multiple barriers" created by PG&E to prevent such mistakes as the erroneous closure of damper MD3, failed in this case. See discussions in General Findings regarding Lack of Communication and/or Coordination and Inadequate Procedures.

222- PG&E is vague as to the scope of corrective actions it intends to take with respect to this problem. MFP Exhibit 49 at 11,12. It has yet to "identify" all of the changes it wishes to implement. Id., corrective actions 2 and 6. Moreover, we consider it inadequate, in light of the potential safety significance of such errors, merely for the Mechanical Maintenance director to "re-emphasize the importance of foremen maintaining their overview responsibilities when resolving field problems." Id., corrective action 3. Clearly, this issue has already been addressed, with only limited success. Without further information demonstrating that this safety problem has been resolved, the Board finds that PG&E's maintenance program remains inadequate.

RESTORATION OF ELECTRICAL PANELS

MFP Exhibit 51: NCR DCO-93-EM-N030 (6/7/93)
MFP Exhibit 52: NCR DC1-93-EM-N019 (5/12/93)

Transcript pages: 887-900

223- In 1993, PG&E documented two events involving failures to return electrical panels to their original configuration following work related activities within the panels. NCR DCO-93-EM-N030 (6/7/93), MFP Exhibit 51 at 1. In both cases, PG&E was unable to determine exactly how the incidents occurred. MFP Exhibit 51 at 8 and NCR DC1-93-EM-N019 (5/12/93), MFP Exhibit 52 at 12.

224- On 4/1/93, the rear hinged panel of the Unit 1 RHF panel was found with no fasteners installed to secure the hinged panel to the main panel. The fasteners were in a plastic bag in the bottom of the panel. This condition "was considered a potential loss of seismic qualification that could have impacted the operability of vital 4kV bus F and its associated diesel generator during a seismic event." MFP Exhibit 52 at 3.

225- PG&E found that the preliminary root cause of this incident was that responsibility for panel restoration was not assigned to any of the groups performing concurrent work in the panel. Id. at 5.

226- Another event occurred in which "covers were not installed in the hot shutdown panel for both Unit 1 and Unit 2." MFP Exhibit 51 at 1. (PG&E did not identify the date of this discovery. The NCR was written on June 7, 1993.) The covers were observed to be lying in the bottom of the back of the hot shutdown panel. The mounting screws could not be located. Id. at 2.

**227- Finding: PG&E's previous corrective action failed to prevent recurrence of a similar event.**

228- PG&E described a previous similar event in NCR DCO-89-EM-N075, which also involved loose or missing fasteners in electrical equipment. PG&E observed that "the common factor in this previous NCR was a lack of problematic guidance in resolving fastener problems. The corrective actions amounted to the establishment of a program for identification and resolution of loose, missing, or damaged fasteners... This program did not prevent the current event, where fasteners were not reinstalled after work by multiple groups during an extended bus outage during 2R5." MFP Exhibit 52 at 9 (emphasis in original).

229- PG&E has noted that there is a potential problematic weakness (i.e., a bus restoration procedure might have prevented this event.) Id. at 14. It further acknowledges that "a programmatic solution" may be required. MFP Exhibit 51 at 8.

230- The Licensing Board finds that the issue involving the reinstallation of fasteners and the restoration of an electrical panel after maintenance activity is not an "isolated" problem, as PG&E has suggested (MFP Exhibit 52 at 14). Three events indicate a programmatic deficiency in

PG&E's maintenance and surveillance practices. Despite an event in 1989, PG&E has failed to establish an effective procedure or program that will ensure that fasteners are reinstalled, covers are replaced and electrical panels are restored to their original configurations. Moreover, as conceded in PG&E proposed finding M-A63, PG&E has yet to complete its "evaluation of root causes and corrective actions" related to the more recent incidents.

**231- Finding: PG&E's safety analysis shows a misunderstanding of or disregard for the safety principles underlying its maintenance responsibilities.**

232- As with numerous other PG&E safety analyses discussed in this case, we are disturbed by the logic and the quality of PG&E's reasoning in determining that these incidents had no safety significance.

233- With respect to the hinged panel on the RHF panel in vital 4kV bus F, PG&E's NCR at first notes that "Engineering evaluation was unable to verify that seismic qualification was maintained in that relays attached to the panel may chatter during a seismic event." MFP Exhibit 52 at 2. According to PG&E, "this condition was considered a potential loss of seismic qualification that could have impacted the operability of the vital 4kV bus F and its associated diesel generator during a seismic event." Id. at 3.

234- However, in the safety analysis which follows, PG&E states that "evaluations" on the tracking and initiating ARs "will document that the F bus and its associated DG would have been operable before and after a postulated seismic event." Id. at 5. In light of the condition in which the panel was found, and the concerns that had just been expressed by PG&E regarding the seismic qualification of the panel, we find this assertion to be glib and unsupported.

235- PG&E also asserts that "only two vital 4kV buses are required to safely shut down the plant, and buses G and H were verified as having the hinged panel fasteners installed." Id. As we have discussed with respect to numerous other safety analyses by PG&E, this analysis ignores the concept that PG&E must assure the redundancy of these safety systems. It is unacceptable for PG&E to argue that although one safety system is disabled through inept maintenance, its companions are available. Both systems must be functional in order to take credit for the redundancy as ensurance that the plant can operate safely. See discussion in the General Findings regarding Multiple Groups and Reduction in Safety Margins.

CONTAINMENT EQUIPMENT HATCH

MFP Exhibit 53: NCR DC2-93-MM-N013 (5/28/93)
MFP Exhibit 54: LER 2-93-003-00 (4/5/93)

Transcript pages: 900-910

236- On 3/10/93, the Unit 2 containment equipment hatch was closed with four bolts in place as required by procedure. But the lead journeyman performed a visual inspection of the equipment hatch from the inside of containment instead of from the outside as required by the maintenance procedure. LER 2-93-003-00 (4/5/93), MFP Exhibit 54 at 2,3. It was on 3/12/93 that it was discovered that the equipment hatch had a visible 1/2" gap in the upper 25% of its sealing surface as observed from outside of the containment. Core offload had been in progress and was immediately suspended after 122 of the 193 fuel assemblies had been removed from the core. NCR DC2-93-MM-N013 (5/28/93), MFP Exhibit 53 at 3 and Tr. at 903.

237- The concern was for the radiological consequences of a fuel damage accident that could have occurred during fuel movement with the containment equipment hatch not fully closed. MFP Exhibit 53 at 8.

**238- Finding: Despite a previous event and an NRC information notice, the maintenance procedure and personnel preparation was not adequate for the hatch closure activity.**

239- PG&E was aware of the need to verify closure of the equipment hatch because of a previous incident and because of industry experience and communication.

240- A previous similar event occurred on 12/2/83 and was addressed in LER 1-83-028-00. Corrective actions included a revision of the maintenance procedure to include: "...inspection of the equipment hatch in greater detail to ensure closure and add additional bolts as necessary to assure that there are no visible air gaps on the sealing surface." Id. at 11.

241- NRC had also alerted licensees about this problem: NRC Information Notice 79-33, "Improper Closure of Primary Containment Equipment Access Hatches," describes an event at Brown's Ferry when the equipment hatch was not fully closed. See MFP Exhibit 53 at 11.

242- PG&E determined the root cause of this incident to be "personnel error, failure to follow the procedure to verify the absence of a containment equipment hatch seal gap from the outside of containment." MFP Exhibit 53 at 6. The Board finds that the procedure itself was not adequate: as PG&E conceded, "independent verification was not required for the containment equipment hatch closure prior to core off-load." Id. In addition, "the Mechanical Maintenance tailboard prior to the containment equipment hatch closure activity was not adequate. The equal spacing of the hatch bolts and visual verification that there was no gap at the hatch sealing area from outside of containment was not discussed during the tailboard." MFP Exhibit 54 at 5.

243- The Licensing Board finds PG&E's maintenance procedure for this activity insufficient to ensure the closure of the hatch and, hence, the safety of the public. Moreover, PG&E failed to respond in a timely or effective way to prior warnings that closure of the containment hatch was a problem.

MANUAL REACTOR TRIP CAUSED BY FAILURE OF A FUSE FOR THE ROD CONTROL SYSTEM

MFP Exhibit 55: LER 1-91-008-00 (5/23/91)
MFP Exhibit 56: NCR DC1-91-EM-N046 (6/10/91)

Transcript pages: 911-912

244- On 4/24/91, a manual reactor trip was initiated in order to terminate an increase in reactor power. The cause of the power increase was an urgent failure of the rod control system which rendered manual control rod movement inoperable. The rod control system failure was caused by the failure of a fuse in the bus duct disconnect to the rod control power supply cabinet. PG&E's investigation revealed that 12 of 15 fuses in similar locations were of the wrong type. NCR DC1-91-EM-N046 (6/10/91), MFP Exhibit 56 at 1.

**245- Finding: PG&E's previous corrective actions were ineffective and failed to prevent the event described above.**

246- In 1987, LER 1-87-016-01 and NCR DC1-87-TI-N109 identified the failure of the ceramic type 30 amp fuses as a generic problem with the rod control system. Failure of power fuses used in control rod drive cabinet 2AC had caused control bank A to lock up. The cause of the fuse failure was poor connection of the end cap with the fusible link. LER 1-91-008-00 (5/23/91), MFP Exhibit 55 at 6. Additionally, NRC IE IN-8762, "Mechanical Failure of Indicating-Type Fuses," identified a similar cold solder joint problem with similar fuses. MFP Exhibit 56 at 11.

247- Corrective action required that all rod control power fuses be replaced with new fiberglass style fuses. "A review of work order C0038363 found that the "old" bus duct fuses were documented as being properly replaced on October 19, 1989." MFP Exhibit 55 at 4. This was obviously not done, for the fuse that failed in the 1991 event was of the 'old' style which was to have been replaced. Additionally, twelve of fifteen fuses in similar locations were found to be the low reliability 'old' style fuses. MFP Exhibit 56 at 1. PG&E admits that the "corrective action would have prevented recurrence if the "new" style fuses had been installed as required." MFP Exhibit 55 at 7.

248- PG&E does not know why these fuses were not replaced with the new fiberglass style fuses, but the Technical Review Group (TRG) concluded it to be a result of "multiple personnel errors... made by three contract electricians who performed the work in October 1989." MFP Exhibit 56 at 13.

249- Whatever the cause, the Licensing Board concludes that corrective actions taken during the Unit 1 third refueling outage in 1989 were inadequate to prevent the recurrence of this event. It is reasonable to expect that the maintenance and surveillance personnel should have been able to conduct a simple act of fuse replacement without mishap. Yet that was not the case. The maintenance and surveillance organization failed to display work that was effective, thorough and attentive to detail. Accordingly, the Board finds that PG&E's actions in this event demonstrates an insufficient maintenance and surveillance program at DCNPP.

LIMITORQUE 2-FCV-37 FAILED TO CLOSE

MFP Exhibit 57: NCR DC2-93-EM-N014 (5/13/93)

Transcript pages: 912-917

250- FCV-37 and 38 are remote manual containment isolation valves for the main steam system to the AFW turbine-driven pump, and are Design Class I. NCR DC2-93-EM-N014 (5/13/93), MFP Exhibit 57 at 9. The valve operators for these valves are Instrument Class IA. These flow control valves are relied upon during loss of main feedwater transient, secondary system pipe ruptures, loss of all ac power (station blackout), loss-of-coolant accident (LOCA) and cooldown. Id. at 8.

251- On 1/31/93, during performance of a routine surveillance test, flow control valve 2-FCV-37 failed to close, either electrically or manually on command from the control room. Id. at 3,4. When the stem cover was removed, a large amount of "Lubriplate" lubricant was found pooled in the stem nut/lock nut depression. Inspection of the stem showed that the stem lubricant was marginal. PG&E believed at that time that the cause of the problem was due to a sticking valve stem. The valve was returned to service on 2/1/93. Id.

252- On 2/4/93, a partial internal actuator inspection found nothing to indicate why the actuator had failed to close. Id. at 4. On 2/5/93, a quality evaluation was initiated. Id. On 2/17/93, votes testing was completed and no problems were noted. Id. On 3/9/93, a manual load cell test determined the as-found thrust to be acceptable. Id.

253- On 3/12/93, PG&E performed an internal inspection of the valve operator, which revealed "significant particulates, water and corrosion." The upper bearing had "visible corrosion." The grease was contaminated with "dirt, rust, metal shavings, etc." Id.

254- On 3/15/93, PG&E determined that "the ability of the 2-FCV-37 to close with full flow differential pressure (DP) was suspect prior to January 31, 1993 with the buildup of corrosion on the upper bearing combined with the degraded stem lubrication." Id. at 5. This was "potentially reportable." Id. at 6.

255- The TRG meeting minutes for March 23, 1993, also state that "subsequent investigation indicates" that the valve "was not operable for a period of time, assumed to be greater than 72 hours, prior to January 31, 1993." Id. at 23. Inoperability of 2-FCV-37 "makes the turbine-driven auxiliary feedwater pump inoperable," thereby exceeding the technical specificiations for DCNPP. Id.

256- At an unspecified date, PG&E also inspected valve operators located in the same pipe rack as FCV-37. Heavy, flaky rust and some standing water were found in the upper section of the stem cover area for 2-FCV-439. Id. at 14.

257- PG&E determined that 2-FCV-37 failed to close due to a combination of corrosion on the upper bearing and degraded stem lubrication. Id. at 2. While PG&E does not explicitly state the cause of the contamination, the TRG minutes identified steam dump condensation as the "most probable cause." Id. at 25. Heavy rainfall was also cited as a possible contaminant. Id. at 20. During maintenance work in 1990, when the valve was overhauled, PG&E workers had neglected to install quad rings during reassembly of the valve operator. Id. at 23. PG&E believes that the quad rings would have protected the valve operator housing from flooding. Id. at 20.

258- Laboratory tests also showed that the lubricants in the valve operator had deteriorated significantly. Grease samples from the main gearbox contained water and dirt contamination. Id. at 4, 25-26. Although PG&E deemed it "usable," it found the grease to be "at the lower range of acceptability." Id. at 26. The grease sample from the upper roller bearing area was "completely black with excessive amounts of large metal particles and water." PG&E found that this grease was "abnormal" and "unacceptable." Id. (See also Control of Foreign Material in the Specific Findings.)

259- Moreover, the tests showed that PG&E had used the wrong lubricant in the valve operator. The upper roller bearing grease was "confirmed to NOT be Lubriplate nor Nebula EP-0," i.e., the grease prescribed for this equipment, and thus "was unacceptable for use as a lubricant." Id. at 26. (See also Storage and Handling of Lubricants in Specific Findings.)

**260- Finding: PG&E failed to perform adequate maintenance on 2-FCV-37 and 2-FCV-439, and did not identify the problem in a timely way.**

261- Thus, by PG&E's own accounting, valve 2-FCV-37, was probably inoperable for some period of time between 1990, when the valve actuator was disassembled, and 1993, when the valve's inoperability was discovered. Given the essential role of this equipment in the safe operation of the plant, and the extensive length of time in which it may have been inoperable, the Board considers this to be a matter of serious concern. The Board also finds that the inoperability of 2-FCV-37 resulted from poor maintenance and surveillance by PG&E, and that these inadequacies have not been resolved sufficiently to find that PG&E can provide reasonable protection to the public health and safety.

262- First, although the NCR does not make it explicitly clear, it appears that PG&E attributes the corrosion and contamination of the valve actuator to contamination by steam condensate or rainfall, which would have been prevented had the quad rings been installed. If indeed the quad rings were required to protect these Class I valve actuators, then we deem it a serious deficiency that PG&E's maintenance procedures did not clearly require the installation of quad rings, or some other means of protecting the valve operators from reasonably foreseeable moisture intrusion. This was such a blatant oversight that it causes us to question the adequacy and completeness of PG&E's maintenance procedures in general.

263- Second, we find that the history of this event demonstrates that PG&E's surveillance program was inadequate to detect the serious internal defects in 2-FCV-37 when its inoperability was first discovered. When the valve failed on January 31, 1993, PG&E removed the stem cover, lubricated the component, and returned it to service. Id. at 3,4. Although PG&E performed a number of tests on the actuator during the following weeks, it did not discover the internal contamination and corrosion until March 12, almost six weeks later. Id. at 4. During this interval, the valve operator was at the very least unreliable, and probably was inoperable. Thus, PG&E continued to operate the DCNPP, relying on defective safety equipment which had wrongly been deemed operable as a result of inadequate maintenance and surveillance activities. See discussion regarding Inadequate Procedures in the General Findings.

264- The only corrective measure that PG&E took in response to this event was to alter its maintenance procedures to ensure that quad rings would be installed in the future. Id. at 16. Nowhere in the NCR does PG&E address the question of whether its procedures should have provided for a more thorough initial inspection of the actuator, or describe any changes that were made to ensure more timely discovery of internal defects. Thus, the Board finds that not only was PG&E's maintenance and surveillance program inadequate to timely detect the inoperability of 2-FCV-37, but that the record contains no indication that changes have been made to ensure timely detection of such internal problems in the future. Therefore, PG&E's maintenance program does not provide reasonable assurance that safety equipment will be maintained in an operable condition.

265- The Board also finds that PG&e's characterization of the "root cause" of the 2-FCV-37 failure is inaccurate and misleading. PG&E claims that the root cause of the event was that the maintenance procedure for 2-FCV-37 did not have sufficient detail to ensure that the quad rings were "properly installed" after Limitorque operator disassembly. Id. at 7. See Tr. at 914,915. But, in fact, the problem was not that the quad rings were improperly installed, but that they were not installed at all. Id. at 5,23. The preliminary root cause as stated in the TRG minutes of the NCR was more accurate: "Procedure deficiency in that MP E-53.10J did not have enough detail to ensure that the quad rings were installed during valve assembly." Id. at 23.

SAFETY INJECTION EMERGENCY CORE COOLING SYSTEM ACCUMULATOR TANKS

MFP Exhibit 59: NRC IR 93-08 (4/27/93)
MFP Exhibit 60: LER 2-87-023-01 (2/1/93)
MFP Exhibit 61: PG&E OSRG March 1992 monthly summary

Transcript pages: 932-946, 2176-2183

266- Examinations of the Safety Injection (SI) emergency core cooling system accumulator tanks in both Units 1 and 2 have identified intergranular stress corrosion cracking (IGSCC) indications. These indications have been found in the accumulator tank stainless steel cladding, nozzles and skirt couplings. NRC IR 93-08 (4/27/93), MFP Exhibit 59 at 4. These cracks have periodically caused leaks in Unit 2 since 1985. Unacceptable indications were identified in Unit 1 in 1992. LER 2-87-023-01 (2/1/93), MFP Exhibit 60 at 2-4.

**267- Finding: PG&E's response to NRC Information Notice 91-05 was untimely and inadequate.**

268- Unit 2 SI accumulators have had a history of problems with cracks in nozzles and welds. PG&E Onsite Safety Review Group (OSRG) March 1992 Monthly Summary, MFP Exhibit 61 at 3. The company that made the DCNPP accumulators, Delta Southern, is the subject of NRC Information Notice (IN) 91-05, "Intergranular stress corrosion cracking in pressurized water reactor safety injection accumulator nozzles" (1/30/91). Id. As described by the NRC, IGSCC "is caused by a combination of factors during manufacture and a suitable incubation time, which is also necessary for indications of cracking to occur. MFP Exhibit 59 at 4. There are four SI tanks in each unit.

Each tank has eight nozzles that are two inch diameter or smaller, two underskirt couplings one inch or smaller and one ten inch nozzle. The cladding, nozzles and skirt couplings were manufactured from either 304 or 304L stainless steel (SS) material. Type 304L is not normally susceptible to IGSCC because it normally has a carbon content less that 0.03%. According to the NRC, it appears that 304 SS cladding, nozzles and skirt couplings became sensitized during accumulator post weld heat treatment after manufacture. Id.

269- At DCNPP, the nozzle material in Unit 1 is "supposed" to be 304L stainless steel, which is not susceptible to IGSCC. MFP Exhibit 61 at 3. In Unit 2, however, 304 stainless steel - which is susceptible to IGSCC - is utilized; thus, in 1992, the OSRG predicted: "It is likely that cracking will be seen in the future, especially in Unit 2." Id. at 2. This prediction was correct, for additional indications were discovered during 2R5 in March of 1993. Tr. at 944.

270- The OSRG criticized PG&E's handling of IGSCC after the IEN 91-05 inspections in several important respects. First, the OSRG expressed a concern that

> No root cause analysis was developed after the initial IEN 91-05 inspections revealed evidence of leaks and UT indications. The presumption was made that cracks in Unit 2 SI Accumulator Tanks were due to IGSCC per the IEN and previous NCRs for Unit 2. No attempt was made to confirm the cause before starting the corrective actions (i.e., nozzle replacements and weld or grinding repairs). An attempt was made to save some samples for carbon content analysis, but most of the cracked material was destroyed in order to make repairs. MFP Exhibit 61 at 2.

The OSRG also found that PG&E's long term corrective actions were

> ...not aggressive nor documented correctly. The only corrective action to prevent recurrence was weekly walkdowns of accessible piping on both units. Under NCR comments, the plan was to inspect the interior of the Unit 1 tank with the most susceptible cladding and do UT and visual inspections of the exteriors of the other Unit 1 accumulators in 1R5. Also, some discussion occurred regarding inspecting the interior of half of the Unit 2 tanks each outage and inspecting external piping on all tanks. However, none of these actions appear in ARs or AEs resulting from the NCR. Id.

Additionally, the OSRG found that

> AE-12 of AR A0241388, claiming that all actions resulting from earlier NCRs and IENs, etc. were implemented, was closed. However, OEA recommendations from review of the IEN were not implemented. An earlier long term corrective action was to replace all possible nozzles and piping in Unit 2 during the next refueling outage (2R5). However, this plan was deleted due to the high cost and schedule impact. Id. (emphasis added).

271- PG&E claims that it rejected the plan to replace all possible nozzles and piping in Unit 2 during 2R5 on the ground that it was unnecessary. Tr. at 940. PG&E says its plan for 2R5 was to replace nozzles "if necessary." Id. However, the weight of the evidence demonstrates that this ad hoc approach to IGSCC is insufficient. PG&E already has ample grounds to believe that all of the high-carbon nozzles will have to be replaced. PG&E is merely delaying the expensive and time-consuming but inevitable replacement of these components. Moreover, as reported by the OSRG, PG&E has failed to think through, document, or even carry out several other of the long-term actions developed after the IEN 91-05 inspections. See MFP Exhibit 61 at 2. Thus, the Licensing Board finds

PG&E's maintenance and surveillance program to be deficient with respect to steam generator nozzle surveillance and replacement.

**272- Finding: PG&E is not certain about the nozzle material used.**

273- As discussed above, the nozzle material in Unit 1 is "supposed" to be 304L stainless steel (not susceptible to IGSCC). In Unit 2, however, 304 stainless steel (susceptible to IGSCC) is utilized. Id. at 3. "The material records are poor, and the documented carbon contents do not correspond correctly with 304L stainless steel (<.03%C) and 304 stainless steel (>.03%C)." Id. NRC was also unsure of the nozzles' content, stating that the "rejected nozzles and skirt couplings **appeared** to have been manufactured from 304 SS material." MFP Exhibit 59 at 4 (emphasis added).

274- PG&E also testified that it had "looked at the carbon content of the accumulators on Unit 1 and we found that the carbon content on three out of the four accumulators was not high, it was a different stainless steel that had low carbon content. And one of the accumulators had high carbon content." Tr. 936.

275- Clearly, knowledge of the carbon content of the steel used in the nozzles and piping would be critical for an effective evaluation of the IGSCC issue. PG&E was notified about this potential problem in 1991. As of March 1993, PG&E is still in the discovery phase of this carbon content issue.

The Licensing Board finds that PG&E failed to maintain adequate records of the composition of the steam generator nozzles, thus undermining its ability to conduct adequate and effective maintenance and surveillance on the nozzles.

**276- Finding: Financial considerations influenced PG&E's decision to delete its corrective action to replace all possible nozzles and piping in Unit 2 during 2R5.**

277- The OSRG stated that "an earlier long term corrective action was to replace all possible nozzles and piping in Unit 2 during the next refueling outage (2R5). However, this plan was deleted due to the high cost and schedule impact." MFP Exhibit 61 at 2.

278- PG&E denies that this deletion was due to the high cost: "We don't put off required maintenance. This was evaluated, it was determined that we didn't have to do this at that time and we didn't." Tr. at 940. But with DNCPP's unique rate payers settlement, the cost of maintenance cannot be passed onto the rate payers. Tr. at 815. The Licensing Board asserts that this situation influences the financial decisions that are made by PG&E management. This is another example in which PG&E based its decision to delete a corrective action on financial rather than on safety considerations. <u>See also</u> Financial Considerations in General Findings.

CORROSION of ASW Annubar, Diesel Fuel Oil and Carbon Dioxide Piping

MFP Exhibit 62: NCR DCO-93-SS-N007 (4/27/93)
MFP Exhibit 63: NCR DC2-92-TN-N028 (10/21/92)
MFP Exhibit 64: LER 1-92-006-01 (10/7/92)
MFP Exhibit 64A: OSRG December 1992 Monthly Report

Transcript pages: 1057-1096
PG&E Testimony: 99-100
NRC Testimony: 10-11

278- The supply lines from the Auxiliary Salt water (ASW) system to the component cooling water (CCW) system are buried 24" pipes, lined with a polyvinylchloride inner "paraliner" and a coal tar outer coating to prevent corrosion. NCR DC2-92-TN-N028 (10/21/92), MFP Exhibit 63 at 2. The safety-related annubar pipes extend from above ground to connect to the buried ASW pipes, and are used during ASW system flow measurements. The horizontal pipe trench/concrete pipeway where vertical annubar pipes exit from the ground also contains two carbon dioxide ($CO_2$) supply lines and a diesel fuel oil (DFO) transfer line, which run horizontally in the pipe trench. Id. Corrosion has occurred on the ASW annubar piping, the DFO piping and the $CO_2$ piping.

280- In February 1990, PG&E identified two areas of surface corrosion on the DFO piping. Id. at 20. In June and July of 1992, PG&E again discovered corrosion on the ASW annubar piping, on piping associated with the DFO train 0-1 and 0-2 and the two fire suppression system carbon dioxide (cardox) lines contained in a pipe trench/pipeway located in the Unit 2 west buttress area trench. PG&E reported the corrosion in LER 1-92-006-01 (10/7/92), MFP Exhibit 64. Ultrasonic testing identified one location on the DFO train 0-1 piping below the minimum wall thickness requirement. MFP Exhibit 63 at 19. A hole 2" x 1 1/16" in diameter was discovered in the ASW annubar piping for ASW train 2-2. Id. at 2.

281- In January of 1993, during piping modification activities, PG&E found rust colored water in the fire protection carbon dioxide (CO2) piping that supplies suppression capabilities to the Unit 2 diesel generators (DGs). NCR DCO-93-SS-N077 (4/27/93), MFP Exhibit 62 at 1. Water was also identified in the 1/2" line to the pilot cabinet. On 2/12/93, the two expansion joints in the header were found to have through-wall leaks that permitted standing water in the pipe trenches to leak into the cardox pipe. Id.

282- PG&E found that, based on examination of the hole and other corroded areas, the root cause of the degraded ASW, DFO and cardox piping was "external general corrosion due to a degradation or breakdown in the coal tar coating exposing the pipe to standing water and the saltwater air environment." The standing water was "due to inadequate drainage, caused by flow blockage by pipe supports and external debris." MFP Exhibit 63 at 9.

**283- Finding: Corrective actions taken after the discovery of corrosion in the DFO piping in 1990 were ineffective and failed to prevent further degradation.**

284- When PG&E discovered two areas of surface corrosion in 1990, the corroded areas were cleaned and recoated. In August of 1991, PG&E also changed the frequency of visual inspection for DFP pipe leakage (STP M-91) from 10 to 5 years. MFP Exhibit 64 at 3. But this did not result in the inspection of the full length of the buttress area piping trenches. According to the PG&E's OSRG December 1992 Monthly Report (MFP Exhibit 64A),

> STP M-91... did not specifically address corrosion problems, nor did the STP require inspection of all DFO transfer piping or the coated ASW piping in the Unit 2 west buttress pipe trench. A QE was not initiated for either of the ARs, nor was NECS requested to evaluate the significance of corrosion on coated piping. Thus, the previous corrective actions were ineffective. MFP Exhibit 64A at 3.

285- In its testimony, the NRC stated its concern "that the problem first surfaced in February 1990, and actions at that time were not sufficient..." NRC found that the action taken "was not sufficiently comprehensive or conservative." NRC Ts. at 10.

286- A previous similar event to which PG&E had responded inadequately, was noted by PG&E in NCR DC1-91-MM-N015.

> This NCR discussed corrosion on a pipe support in the ASW vault. The root cause was degradation of the protective coating on the support, but it could not be determined whether the coating had been improperly applied, or damaged during maintenance. Corrective actions expanded the scope of routine inspections to include other components in ASW and DFO vaults (<u>but not the DFO trenches</u>). MFP Exhibit 63 at 14 (emphasis added).

287- Prior to its 1993 discovery of leakage and degradation in CO2 piping, PG&E had identified the "potential" for such degradation and leakage of CO2 piping in NCR DC2-92-TN-N028, 'ASW Annubar Line/DFOT Line Corrosion.'" MFP Exhibit 62 at 13. Yet this previous prediction failed to prompt PG&E to take effective corrective action.

288- The Board finds that these instances of PG&E's insufficient corrective actions demonstrate a deficiency in its maintenance and surveillance program.

**289- Finding: PG&E's maintenance and surveillance program was not adequate to detect and sufficiently control the extensive corrosion that has occurred in the pipe trench/pipeway.**

290- As discussed in NCR DC2-92-TN-N028, "the existing surveillance procedure did not specifically require inspection for pipe corrosion in the pipe trench/pipeway" or "provide instruction for identification of corrosion on piping." Id. at 7,8. Instead, PG&E "assumed that the problem reporting process and the diligence of plant staff would cover this condition..." Id.

291- Clearly, it was insufficient for PG&E to rely on the diligence of plant employees to discover this piping corrosion. By the time the corrosion was noticed, it was extensive: "On June 21, 1992, a work crew was inspecting the DFO trenches to determine the extent of an acid/caustic spill in the Unit 2 west buttress. Corrosion was found on the DFO Train 0-1 system piping and two fire suppression system CO2 lines." MFP Exhibit 64 at 6. Upon further investigation, additional corrosion was discovered. And in one location (DFO train 0-1 piping), the piping had degraded to such an extent that the piping was below the minimum wall thickness requirement. MFP Exhibit 63 at 19. A few days prior to this, a hole 2" x 1 1/16" in diameter was discovered in the ASW annubar piping for ASW train 2-2. Id. at 2.

**292- Finding: There was inadequate initial application and maintenance of the coal tar protective coating which was intended to prevent corrosion on the piping in the trench/pipeway.**

293- PG&E stated in NCR DC2-92-TN-N028 that "there was inadequate initial application and maintenance of the coal tar protective coating on the underside of the DFO and cardox piping." Id. at 26. "Also, the bottom 1/3 of the piping was not adequately coated with coal tar due to the close quarters in the trench." Id. at 8. Thus, some of the corrosion is attributable to PG&E's inadequate maintenance practices, i.e., its failure to properly apply and maintain the coal tar protective coating on these pipes.

**294- Finding: The trench/pipeway was not maintained in an adequate manner to prevent the accumulation of water.**

295- At the hearing, PG&E testified both to the susceptibility of the trench to water accumulation, and the difficulty of inspecting it for water. According to PG&E witness Giffin, the trench is a long, horizontal run. It is not sloped well for drainage. It is outside, and the drainage holes are small. These holes easily become clogged with debris and prevent the water from draining. When it rains, the water comes off the turbine building and flows into the trench. Tr. at 1072. Additionally, "these trenches are covered with security grating. So they're covered with steel plates so that you can't even routinely... determine by looking into this trench whether there was any water in it." Tr. at 1074.

296- PG&E found that the root cause of the pipe corrosion was breakdown of the coal tar coating and exposure of the piping to standing water and the saltwater/air environment. After the identification of further corrosion in 1992, it was noted that "the standing water in the trench was due to inadequate drainage, caused by flow blockage by pipe supports and external debris." MFP Exhibit 64A at 2. PG&E also found that "...a hard corrosion/sand mix was found packed around the buried main ASW flanges and bolts... Examination of the trench/pipeway revealed that there were wood blocks and debris that had not been removed." MFP Exhibit 63 at 8.

297- At the time that NCR DC2-92-TN-N028 was written, there were no procedures in place to maintain adequate drainage in the pipe trench/pipeway. Tr. at 1072 (Giffin). Clearly, the condition of the trench was not being adequately maintained. The Board finds that PG&E's maintenance and surveillance program was severely deficient in this regard.

Furthermore, this deficiency created the environment in which corrosion would surely occur.

**298- Finding: PG&E has been unacceptably slow to respond with corrective actions to alleviate the corrosion of pipes in the pipe trench/pipeway.**

299- Galvanic corrosion of pipes was first identified in the pipe trench/pipeway in 1990. MFP Exhibit 64 at 3. However, this did not prompt PG&E to institute a comprehensive program to inspect all the piping in this trench. MFP Exhibit 64A at 3. Furthermore, not until 1992 did PG&E institute a program to prevent the accumulation of water in the trench (a contributing factor in the development of the corrosion). Tr. at 1064.

300- Moreover, it was not until June of 1992 that PG&E assembled a "corrosion task force" to take a more comprehensive look at piping systems subject to exterior corrosion. Tr. at 1063. PG&E promises that the existence of this task force will remedy what is concededly a generic problem of galvanic corrosion on the exterior surfaces of pipes. Tr. at 1062,1063,1064,1082,1088. We are concerned that this corrosion task force will also be slow to respond: "One location considered a potential problem area is where the ASW lines exit the intake structure. Although excavation of the lines at this location will be difficult, it may prove necessary due to the probable saltwater in that location." MFP Exhibit 63 at 35. It has been fourteen months since this corrosion task force has been in place and this "problem area" has not yet been examined. Tr. 1082.

301- PG&E has been lax and untimely in responding to the incidents of galvanic corrosion described above. Moreover, it has yet to complete its evaluation of the admittedly generic problem or to implement a response. We find that the record shows that PG&E's maintenance and surveillance program has been severely inadequate to prevent, monitor, or repair galvanic corrosion on safety related piping. The incidents of ASW degradations demonstrate a programmatic weakness which must be resolved before the Board can find that PG&E's maintenance and surveillance program is adequate.

**302- Finding: PG&E's proposed corrective actions are unsubstantiated and should not be considered in this process.**

303- PG&E promises that the design of the trench will be changed to minimize the potential for the standing water. PG&E plans to raise the pipe in the trench. It intends to remove the cardox piping from the trench and replace all of the diesel oil piping. These changes are to occur "in the near future." PG&E witnesses could not recall which outage this is all scheduled for, "but it is not in the too distant future." Tr at 1084. These are unsubstantiated promises which cannot be relied upon for any use in this evidentiary process. Additionally, these promises of future actions do not address or allay our concern regarding the errors and inattentions that previously had been demonstrated by PG&E's maintenance and surveillance department.

**304- Finding: PG&E determined that the DFO and ASW annubar piping remained operable despite the corrosion. PG&E instituted compensatory measures to compensate for the inoperable cardox system. PG&E's operability/compensatory determination, however, is not an indication of an effective maintenance and surveillance program. It is an indication that PG&E was lucky this time.**

305- PG&E claims that the leaking from the ASW piping did not affect operability. Tr. at 1062. PG&E claims that the corrosion identified in the DFO piping in 1990 and 1992 did not affect the operability of the system. Tr. at 1063. PG&E admits, however, that it could not guarantee the effectiveness of the cardox system. Thus, a continuous fire watch in the DFO rooms was implemented which, according to PG&E, satisfied the requirement. Tr. at 1066.

306- PG&E claims that these three cases of corrosion on the ASW annubar, the DFO line piping and the cardox piping do not suggest a breakdown in the maintenance and surveillance at the plant. As PG&E witness Giffin testified,

> If they indicated a breakdown, then I would have had a system that was inoperable, or I would not have had a comp measure in place to address it prior to any failure. I think that these instances were found during an investigation or surveillance. Discrepancies were found, and actions have been put in place to rectify the problem. Tr. at 1071.

307- The Board takes exception to this claim. PG&E's deficient maintenance and surveillance program at DCNPP involving the ASW annubar, DFO and CO2 piping and the drainage in the trench/pipeway resulted in extensive corrosion. The breakdown in PG&E's maintenance and surveillance program is exemplified in its inability to alleviate corrosion of pipes in the trench/pipeway that was identified in 1990.

308- There were two instances of through-wall leaks and one where the minimum wall thickness requirement was not met. The fact that two of the three systems could be declared operable despite this degradation was pure luck in that they were identified in time. (Note that the discovery of the 1992 corrosion was due to investigation following a chemical spill in the area. The 1993 corrosion discovered on the CO2 system was made known by the rust colored water that came pouring out during piping modifications. These discoveries were not due to any thorough surveillance for corrosion on the part of PG&E.) The cardox system **was** inoperable, and PG&E elected to take the stop-gap measure of instituting a continuous fire watch rather than shutting down and making the repairs necessary to keep the system running. PG&E's maintenance and surveillance system, in this instance, exhibited gross negligence and inadequacy.

**309- Finding: PG&E's failure to prevent the accumulation of water in the trench/pipeway contributed to the development of corrosion on the ASW, DFO and CO2 piping. This situation**

**is similar to PG&E's failure to maintain the sump pumps in the vaults; the submergence of the cables contributed to the severe degradation and eventual failures of the 12kV cables.**

310- The accumulation of water may seem to be a small thing compared to the complicated technology of an operating nuclear reactor. But this small thing has led to corrosion and degradation of needed equipment, some of it safety related. In both cases (the trench/pipeway and the sump pumps), no maintenance procedures were in place to prevent the accumulation of water. These two situations affirm that the maintenance and surveillance program at DCNPP is deficient.

**311- Finding: This is an example of inadequate coordination between maintenance and operations personnel.**

312- NRC testified that

> An additional NRC concern involved the coordination between the maintenance and operations organizations, in that the other fuel oil system had been taken out of service leaving the corroded system in service. Only later did the Licensee determine, by analysis, that the fuel oil system had been operable despite the corrosion. NRC Ts. at 10,11.

313- The Board finds that this is an example of a disturbing and unacceptable pattern in which poor coordination between maintenance and surveillance personnel led to safety problems. <u>See also</u> General Findings regarding Lack of Communication and/or Coordination.

CONTROL OF MEASURING AND TEST EQUIPMENT

MFP Exhibit 65: NCR DCO-93-MM-N002 (4/12/93)
MFP Exhibit 66: PG&E reply to NOV in NRC IR 91-04 (5/10/91)
MFP Exhibit 67: NCR DCO-90-MM-N089 (4/8/91)
MFP Exhibit 69: NRC IR 90-29 (2/8/91)
MFP Exhibit 70: NRC IR 91-04 (3/4/91)
MFP Exhibit 71: NRC EA 91-028 Report of Enforcement Conference with PG&E Management, NRC IR 91-06 (4/11/91)

Transcript pages: 1096-1112, 2189-2197
PG&E Testimony: 102-103

314- Deficiencies in the control of Measuring and Test Equipment (M&TE) were first identified at DCNPP in 1985. NRC IR 90-29 (2/8/91), MFP Exhibit 69 at 1.

315- Subsequent audits and surveillances in 1989 and 1990 confirmed the continuing nature of M&TE documentation deficiencies in mechanical maintenance. Id. at 1-5. The NRC found these deficiencies were "significant." Id. at 3. Furthermore, "the programmatic weaknesses were not adequately dealt with to preclude recurrence." Id.

316- In April of 1991, the NRC issued a Severity Level IV violation for the period from November, 1989 through December, 1990, charging that

> effective corrective actions were not implemented to preclude repetition of significant deficiencies in the control and issue of measuring and test equipment used in activities affecting quality which were identified in licensee Surveillance and Audit reports QCS 89-0175, 90-0030, 90-126 and 90812T. In addition, a nonconformance report was not initiated to identify this lack of corrective action. NRC EA 91-028 Report of Enforcement Conference with PG&E Management, NRC IR 91-06 (4/11/91), MFP Exhibit 71, Enclosure 1 at 1,2.

317- Despite corrective actions taken by PG&E, problems involving M&TE have persisted. QA Audit 92038I in 1992 identified several M&TE deficiencies. PG&E conceded that "this appears to be a repeat of one of the problems identified under NCR DCO-90-MM-N089." NCR DCO-93-MM-N002 (4/12/93), MFP Exhibit 65 at 1.

**318- Finding: The identified M&TE problems are long standing, recurring and continuing.**

319- Deficiencies in the control of Measuring and Test Equipment (M&TE) were first identified at DCNPP in 1985. MFP Exhibit 69 at 1. Subsequent audits and surveillances in 1989 and 1990 confirmed the continuing nature of M&TE documentation deficiencies in mechanical maintenance. Id. at 1-5.

320- The NRC noted in their IR 90-29 that "individual discrepancies discussed throughout the report contributed to the situation and involved repetitive cases of problems with following M&TE procedures, improper dispositioning of action Requests and Quality Evaluations, and failure to correct recurring deficiencies." Id., cover sheet.

321- The NRC issued two Severity Level IV violations involving M&TE deficiencies: one in 1985 (MFP Exhibit 69 at 1) and the other in 1991 (MFP Exhibit 71, Enclosure 1).

322- Despite corrective actions taken by PG&E, problems involving M&TE persist. QA Audit 92038I in 1992 identified several M&TE deficiencies. "This appears to be a repeat of one of the problems identified under NCR DCO-90-MM-N089." MFP Exhibit 65 at 1. TRG minutes in NCR DCO-93-MM-N002 note that "the QA audit pointed out the fact that there still is a problem with M&TE." Id. at 13.

**323- Finding: PG&E's maintenance and surveillance organization failed to respond promptly to the M&TE deficiencies.**

324- The NRC found that "the examination of M&TE controls conducted during this inspection [NRC IR 90-29] confirmed the continuing nature of M&TE documentation deficiencies in mechanical maintenance. Some of the deficiencies identified were readily apparent, and should have been found prior to the inspection by the licensee." MFP Exhibit 69 at 1.

325- Quality Assurance Audit 90812T, conducted during the period of June 20 to August 9, 1990, "identified and stated that 'QC's slow response to continue to pursue and investigate known problems further to reach conclusions and correct deficiencies was considered weak.'" Id. at 5.

326- In an Enforcement Conference that was held in 1991, the NRC expressed concerns "regarding the timeliness and thoroughness of your overall corrective action program implementation for an extended period of time." MFP Exhibit 71, cover letter at 1.

327- In response to the 1991 violation noted above, PG&E agreed that "plant management should have been more aggressive in taking timely and effective action to assure that the deficiencies were corrected." PG&E reply to NOV in NRC IR 91-04 (5/10/91), MFP Exhibit 66 at 2.

328- The Licensing Board finds that the evidence cited above demonstrates that PG&E's maintenance organization was slow to respond to the M&TE deficiencies initially identified in 1985. Furthermore, these problems have not yet been fully resolved. This is indicative of an insufficient maintenance and surveillance program at DCNPP.

**329- Finding: Corrective actions taken by the licensee were ineffective to prevent the recurrence of the M&TE deficiencies.**

330- In NRC IR 90-29, the NRC concluded that

> Licensee personnel did not deal effectively with the overall findings of their own audits and surveillances. This lack of effective corrective action was recognized in another licensee audit in May, 1990. However, effective corrective actions were still not taken. MFP Exhibit 69 at 1.

Additionally,

> The Licensee had inappropriately closed a 1987 nonconformance report which identified M&TE deficiencies was closed without assuring that the root cause was identified and effective corrective actions were implemented to preclude recurrence. Id.

331- The NRC reported that

> QCS 89-175 had identified significant deficiencies which resulted in nine action requests being issued to address individual discrepancies... The audit report indicated that a mechanical maintenance foreman stated there had been numerous discussions at all management levels to rectify the situation. It does not appear, however, that to the NRC inspectors whether any substantial action was taken to correct the situation as a result of those management discussions. Id. at 2.

332- According to Quality Assurance Audit 90812T (1990),

> no action request, nonconformance report, or finding was identified... The inspectors concluded that audit findings did not address concerns that appeared to be

contributory to the recurring deficiencies. This is an example of inadequate corrective action. Id. at 5,6.

333- In response to QCS90-030,

> The inspectors found that, although the audit identified significant recurring deficiencies for which previous corrective action was inadequate, no Actions Requests, (ARs), Quality Evaluations (QEs), or Audit Finding Reports (AFRs) were written specific to the problem of inadequate corrective action for significant deficiencies. The inspector found that no written response was required to address the overall conclusions of the surveillance report. These conclusions were based on the auditor's evaluation of the significance of the individual observed deficiencies as indicators of the effectiveness of the program in achieving its quality objectives. Individual deficiencies were addressed under subsequent Action Requests. Apparently, the licensee did not recognize that the programmatic weaknesses, which allowed the individual deficiencies to occur, required correction. Therefore, the programmatic weaknesses were not adequately dealt with to preclude recurrence. Id. at 3.

334- The NRC issued a Severity Level IV violation for these conditions in IR 91-04. It stated that

> during the period from November, 1989 through December, 1990, effective corrective actions were not implemented to preclude repetition of significant deficiencies in the control and issue of measuring and test equipment used in activities affecting quality which were identified in licensee Surveillance and Audit reports QCS 89-0175, 90-0030, 90-126 and 90812T. In addition, a nonconformance report was not initiated to identify this lack of effective corrective action. MFP Exhibit 71, NOV, Enclosure at 1.

335- In response to the violation, PG&E agreed that

> plant management should have been more aggressive in correcting these weaknesses in a timely and effective manner...the root causes of the deficiencies were the failures of not only the responsible line organization to pay attention to detail, but also of the quality organizations and senior plant management to insist that the deficiencies be corrected in a timely manner. PG&E recognizes that the M&TE deficiencies identified in the NOV are symptomatic of issues relating to our overall

> corrective action implementation program... MFP Exhibit 66 at 3.

336- In an Enforcement Conference that took place in 1991, the NRC expressed concerns

> regarding the timeliness and thoroughness of your overall corrective action program implementation for an extended period of time. These concerns have been brought to your attention in previous inspection reports, the latest SALP report, and were also discussed during our last management meeting in November 1990. The circumstances surrounding the mechanical M&TE issue, addressed here and in the associated NRC Inspection Reports, provide additional examples that your program for corrective action has not been fully effective. As we discussed at the Enforcement Conference, several barriers existed to assure that the weaknesses in the mechanical M&TE area were promptly corrected. The responsible line organization, quality control, quality assurance, and senior management all had opportunities to insist on correcting the programmatic weaknesses. None of these organizations functioned effectively to deal with the M&TE problem. MFP Exhibit 71 at 1.

337- NCR DCO-93-MM-N002 described more recent M&TE deficiencies. Moreover, PG&E noted that the deficiencies appeared "to be a repeat of one of the problems identified under NCR DCO-90-MM-N089." MFP Exhibit 65 at 1. The Licensing Board thus concludes that, despite PG&E's continuing attempts to remedy the deficiencies in M&TE, corrective actions to prevent recurrence have been ineffective.

**338- Finding: PG&E management was insufficiently involved in the resolution of the M&TE deficiencies.**

339- In QP&A 90-126, the NRC noted that "it was not clear that the auditor's findings were recognized and dealt with effectively by management." MFP Exhibit 69 at 4.

340- In 1991, PG&E determined the root cause of the recurring M&TE deficiencies was inattention to detail, inadequate acceptance of, and insufficient management attention to M&TE program requirements. A program was initiated in late 1989 to purchase additional M&TE equipment and transfer the responsibilities of MM M&TE to I&C, yet "a failure to recognize continuing problems and elevate them to upper management's attention contributed to the failure to initiate an NCR and resolve the issue." NCR DCO-90-MM-N089 (4/8/91), MFP Exhibit 67 at 1.

341- In response to a violation issued in 1991 (noted above), PG&E agreed that

> plant management should have been more aggressive in correcting these weaknesses in a timely and effective manner... the root causes of the deficiencies were the failures of not only the responsible line organization to pay attention to detail, but also of the quality organizations and senior plant management to insist that the deficiencies be corrected in a timely manner. PG&E recognizes that the M&TE deficiencies identified in the NOV are symptomatic of issues relating to our overall corrective action implementation program... MFP Exhibit 66 at 3.

342- During an Enforcement Conference that took place in 1991, the NRC noted that

> the responsible line organization, quality control, quality assurance, and senior management all had opportunities to insist on correcting the programmatic weaknesses. None of these organizations functioned effectively to deal with the M&TE problem. MFP Exhibit 71, cover.

> Mr. Martin [NRC Regional Administrator] concluded the meeting by stating that the fundamental weakness in the licensee's performance had been the failure of management to ensure that timely corrective actions were being

taken. Mr. Shiffer [PG&E Senior vice President and General Manager] agreed with this summation. Id.

343- In a 1993 NCR, PG&E determined that the root cause of the continuing M&TE problems was personnel error due to inattention to detail and failure to comply with applicable administrative procedures. PG&E found that the contributory causes included ineffective management commitment to the M&TE program and personnel not held accountable. MFP Exhibit 65 at 5.

344- Hence, the Licensing Board finds that PG&E's management is not sufficiently involved in the resolution of the long standing and recurring M&TE deficiencies.

**345- Finding: The recurring M&TE deficiencies have safety significance.**

346- PG&E claims that "there was no safety significance to these deficiencies." Tr. at 103. Yet, according to an NRC inspection report, the findings "represent a significant safety matter because they indicate a chronic programmatic weakness in the control of MM M&TE, which may have, or at least had the potential to adversely impact installed safety related equipment." MFP Exhibit 70 at 2 and cover pages.

347- Moreover, we reject PG&E's argument that there was no safety significance to these M&TE deficiencies because there was no **actual** adverse impact on safety related equipment. Tr. at 1107. See discussion regarding Inadequate and Incorrect Safety Analyses of Safety Significance, which rejects this type of analysis. The potential for significant adverse effects due to the M&TE deficiencies are real and substantial. The fact that safety related equipment has not yet been affected indicates that PG&E has thus far been lucky, not that these M&TE deficiencies have no safety significance.

CENTRIFUGAL CHARGING PUMP 2-1; DEGRADED COUPLING

MFP Exhibit 73: NCR DC2-92-MM-N031 (3/12/93)

Transcript pages: 1120-1125

348- On 6/30/92, PG&E identified an increase in vibration on Centrifugal Charging Pump (CCP) 2-1. While attempting to take a gear lube sample from the motor-to-speed increaser coupling during investigation of this problem, the coupling sleeve was found to be stiff due to hardened lubricant. While ECCS trains 1-1, 1-2 and 2-2 have not experienced coupling problems, this was the third occurrence involving CCP 2-1. NCR DC2-92-MM-N031 (3/12/93), MFP Exhibit 73 at 1.

349- PG&E found that the root cause of the degraded condition of the coupling was due to the following:

1. vendor recommendations were not clearly stated;
2. alignment tolerances and data were not specifically stated on the work order;
3. alignment data sheets were not provided or utilized;

4. no evaluation was performed by Mechanical Maintenance engineering to determine the acceptability of the alignment;

5. the actual relative thermal movement between the shafts are different that indicated by the manufacturer's cold offset recommendations;

6. the grease type used was not as durable as the special grease available from the coupling manufacturer;

7. the cleaning and lubricating technique during preventive maintenance varies greatly because the outer flange cannot be pulled back to allow good cleaning, inspection, and repacking of the coupling at the gear teeth.

Id. at 3,4.

8. vendor recommendations were not implemented.

Id. at 14.

**350- Finding: Previous corrective actions should have prevented recurrence of this event, but failed to do so.**

351- PG&E claims that this event demonstrates the effectiveness of the Predictive Maintenance program because the coupling was replaced prior to any failure. Id. at 4. The Licensing Board finds that , to the contrary, this incident demonstrates the failure of PG&E's maintenance and surveillance organization to make effective changes based on previous experience.

352- CCP 2-1 had experienced excessive coupling wear in April of 1989 due to misalignment of the motor with respect to the speed increaser. Id. at 9. In response, PG&E took corrective actions, including "development of more detailed alignment instructions and more complete post-maintenance testing following shaft, coupling, bearing maintenance;" and "expanded alignment instructions" in the training program. Id. However, as PG&E conceded, "the corrective actions in this previous event did not preclude [the 1992] event, since these corrective actions did not establish a procedure which contains the vendor's base line, (procedure MP M-56.19 was not in existence), no alignment data sheets were in existence, vendor information was ambiguous, difficult to understand, the vendor recommendations were not followed, tolerance and data were not called out." Id. 9,10.

353- Thus, in April of 1989, PG&E became cognizant of vendor deficiencies (information ambiguous or lacking) and recognized its own maintenance inadequacies (vendor recommendations were not followed), yet that situation was not rectified. When this subsequent event occurred in June of 1992, adequate vendor information was still unavailable and vendor recommendations still had not been implemented. The Board must ask: why was this situation allowed to exist? The Board concludes that PG&E's maintenance and surveillance program should have been able to preclude the 1992 event and failed to do so. See also discussion in General Findings regarding Untimely or Ineffective Response to Maintenance Problems.

<u>UNIT SHUTDOWN DUE TO INOPERABLE HIGH PRESSURE TURBINE STOP VALVE</u>

MFP Exhibit 74: LER 2-92-003-01 (3/10/93)

Transcript pages: 1125-1138

354- On March 22,1992, a manual shutdown was commenced for Unit 2 when PG&E determined that one high pressure turbine stop valve (FCV-144) was inoperable. LER 2-92-003-01 (3/10/93), MFP Exhibit 74 at 1. FCV-144 is a hydraulically-actuated swing check valve which protects the high pressure turbine from overspeed. "Overspeed protection is necessary to preclude turbine rotor failure and associated turbine generated missiles." Id. at 2.

355-PG&E disassembled FCV-144 and determined that "the nut that retains the valve disc to the valve swing arm had disengaged from the disc stem, allowing the valve disc to become separated from the valve swing arm. When the valve separated from the swing arm, it caused a partial blockage of steam flow through Main Steam Lead 2." <u>Id.</u> at 4,5.

356- PG&E has been unable to identify the root cause of this equipment failure. It postulates two modes of failure: (1) unscrewing of the nut off the stem; or (2) a failure of the nut/disc stem threaded joint. <u>Id.</u> at 4. Either one of these failure modes would have occurred during initial installation or during its previous overhaul. Tr. at 1133,1134.

**357- Finding: PG&E may have caused an undetectable failure through improper maintenance.**

358- As discussed above, the failure of this valve may have been caused by improper maintenance at some earlier time. PG&E testified that for either of the postulated failure modes identified above, the problem becomes apparent once the valve is disassembled. Tr. at 1129. But, otherwise, PG&E has no way to detect the deficient component until it fails. Tr. 1131.

358- As discussed in our General Findings regarding Previous Maintenance Problems Caused Undetectable Failures, the Board is concerned that PG&E's maintenance activities are causing undetectable failures that may create safety problems at a future time. We are concerned that these maintenance activities, such as overhauls of valves, may not be getting the degree of supervision that is necessary to ensure that they are performed accurately.

<u>DIESEL GENERATOR 2-2 FAILURE TO ACHIEVE RATED VOLTAGE</u>

MFP Exhibit 75: NCR DC2-93-MM-N001 D5 (3/10/93)
MFP Exhibit 76: Special Report 92-06 (1/27/93)

Transcript pages: 1138-1145

360- On 12/29/92, during performance of a Surveillance Test Procedure (STP) on Diesel Generator (DG) 2-2, the DG started and accelerated, but did not load because the generator output voltage reached only 105V instead of the required 110-128V. Investigation determined that all four generator slip ring brushes were out of position. Special Report 92-06 (1/27/93), MFP Exhibit 76, enclosure at 1. DG 2-2 was unavailable for a total of 40 hours and 45 minutes. Id. at 2.

361- As required by its technical specifications, PG&E submitted a special report to NRC regarding this incident. Special Report 92-06 (1/27/93), MFP Exhibit 76.

**362- Finding: This incident demonstrates procedural inadequacies and failure to ensure that maintenance is performed by qualified technicians.**

363- We disagree with PG&E's claim that this incident shows a properly functioning maintenance program. Tr. at 1140-41. Rather, the incident demonstrates two problems with the maintenance program: inadequate procedures, and a lack of communication or supervision among electrical and mechanical maintenance personnel.

364- First, PG&E concedes that the procedures for this task were inadequate. The "root cause" of the mispositioned slip ring brushes was attributed to "inadequate information available to personnel regarding the extent that subassemblies could be affected during required inspections." MFP Exhibit 76 at 5. In response, PG&E revised its maintenance procedures for this task. Id. at 7. While one procedural deficiency may be considered an "isolated incident," as PG&E would characterize this, we find that it is part of a repetitive pattern of such problems. See discussion regarding Inadequate Instructions in the General Findings.

365- Second, the Board finds that the manner in which maintenance was performed on this diesel generator reflects inadequate coordination between the electrical and mechanical subdivisions of the maintenance department. The job was performed entirely by a mechanical maintenance technician, "who did not recognize that what he was doing could have affected the electrical brushes." Tr. at 1140. Thus, an electrical maintenance technician should have participated. MFP Exhibit 76 at 4, 7, Tr. at 1144. We consider it to be more than a minor personnel error when PG&E fails to assign a technician with the correct expertise and training to perform a maintenance task.

366- We find PG&E's lack of attention to the need for coordination to be a matter of particular concern here, where the maintenance task being performed was somewhat unusual: as PG&E stated in the NCR, "barring the engine over with the generator bearing end cover removed, without provision for holding the slip ring brushes in place is not a normal evolution." Id. at 5. The procedure was performed in order to provide NECS-Engineering with data for an investigation of a vibration problem on another diesel generator. Id. Accordingly, since this was a procedure with which the mechanical maintenance technician was not routinely familiar, it was all the more important that PG&E enlist the services of an electrical technician who "would have understood that he would have had to worry about the brushes." Tr. at 1143.

368- PG&E also claims that this incident shows that the maintenance problem works because tests done after the repairs revealed the existence of the mispositioned slip rings, and they were fixed. Tr. at 1140. However, PG&E's testimony conveys an exceptional reliance on post-maintenance testing to correct inadequate maintenance, rather than improvement of the maintenance activity. It further raises the concern that this maintenance error might not have been revealed through post-maintenance testing, and might not have surfaced until the diesel generator was called on during an accident. As described by PG&E witness Giffin, the initial test, in which the error was made, involved turning the rotor on the diesel generator. Tr. at 1140. "And when they did that the slip rings, the brushes, <u>slipped out of place.</u>" <u>Id.</u> If the brushes had not slipped at that juncture, then subsequent post-maintenance testing might not have revealed the technician's error. Thus, it may be more a matter of luck than "good maintenance" that this error was discovered.

MISSED ALERT FREQUENCY STP FOR AUXILIARY SALT WATER PUMP 1-2 and COMPONENT COOLING WATER VALVE CCW-2-RCV-16

MFP Exhibit 77: NCR DC2-93-TS-N005 (3/3/93)
MFP Exhibit 78: NCR DC1-92-TP-N052 (2/4/93)
MFP Exhibit 79: LER 1-92-024-00 (11/17/92)

Transcript pages: 1145-1153

Auxiliary Salt Water Pump

369- Two events occurred involving the auxiliary salt water (ASW) pump 1-2. ASW pumps are required to be functionally tested in accordance with STP P-7B on a 92-day frequency to meet the requirements of TS 4.0.5. NCR DC1-92-TP-N052 (2/4/93), MFP Exhibit 78 at 2. PG&E reported these events to the NRC in LER 1-92-024-00 (11/16/92), MFP Exhibit 79.

370- The first event occurred on 8/21/91, when ASW pump 1-2 was removed from service to perform STP P-7B. The testing results determined the results to be satisfactory and the pump was returned to service. It was later recognized, however, that the incorrect ASW pump 2-2 volume 9 curve was incorporated in STP P-7 and was used to define the action levels for ASW pump 1-2. When the proper data was obtained from the ASW pump 1-2 volume 9 curve, it showed that the pump exceeded the action high level for differential pressure. It should have remained inoperable. MFP Exhibit 79 at 2,3.

371- PG&E found that the root cause of this event personnel error due to inattention to detail. The employee failed to recognize that the data was incorrect. The employee read ASW pump 2-2 curve instead of 1-2 curve. MFP Exhibit 78 at 5. PG&E also noted the following contributory causes:

> 1. The shift foreman failed to recognize that the wrong pump curve was attached to the data package. The unit designation was clearly marked on the pump curve.
>
> 2. The method of determining the base line for the ASW pump is cumbersome. Personnel must go to another document to pull the pump base line data rather than have an appendix in the procedure for each pump.
>
> 3. The test performer failed to identify that the wrong pump curve was used.
>
> 4. The annubar readings are crucial to the proper data collection. Based on other valid tests, the data obtained in this specific test is questionable.

MFP Exhibit 78 at 6.

372- In the second event, on 11/14/91, STP P-7B was again performed on ASW Pump 1-2 and the test reviewer incorrectly determined that the results were satisfactory. He mistakenly assumed that the test results were acceptable, since the data was similar to previous test results. He failed to recognize that ASW pump 1-2 was below the alert low level for differential pressure and should be placed on alert. The pump differential alert low warns plant engineers that the pump is only slightly within the acceptable range and should be tested and evaluated on a more frequent basis. PG&E also attributed the root cause for the second event to personnel error. MFP Exhibit 78 at 1-3. See discussion in General Findings regarding Breakdown of Multiple Barriers.

373- It wasn't until 10/10/92, that the pump history was questioned and PG&E noticed that this pump should have been placed on alert and on accelerated testing as required by TS 4.0.5. Id. at 3.

374- Three previous similar events were noted. (1) NCR DC1-92-TN-N003 addressed a missed alert frequency STP on the boric acid transfer pump 1-2. Corrective actions that should have prevented this event were taken after this event occurred. (2) NCR DC1-86-TN-N086 addressed a missed surveillance alert for FCV-366. (3) NCR Inspection Report 86-14 and 86-15, Notice of Violation, cited a concern regarding the effectiveness of PG&E's TS surveillance test program. Id. at 11-13.

Component Cooling Water Valves

375- Component cooling water (CCW) valves are required to be functionally tested in accordance with STP V-3H12 on a 92-day frequency to meet the requirements of TS 4.0.5. Because the component cooling water surge tank normally vents to the atmosphere, radiation monitors are provided in the CCW discharge headers. If deviations fall within the alert range, the frequency of testing is doubled until the cause of the deviation has been determined and the condition corrected. NCR DC2-93-TS-N005 (3/3/93), MFP Exhibit 77 at 2.

376- STPV-3H12 was performed on 10/16/92. Since the stroke time of 5.506 seconds exceeded the previous stroke time of 1.613 seconds, the test frequency should have changed from a 92-day to a 31-day. The surveillance coordinator typed AR to go to the RT library AR. But, he exited PIMS incorrectly and lost the request. Id. at 3,4.

377- STP V-3H12 was performed on its normal 92-day frequency on 1/16/93. On 1/22/93, the test reviewer noted the missed alert frequency surveillance testing. Id. at 6.

378- PG&E determined the root cause to be personnel error in that PIMS was exited incorrectly and prevented the recurring task scheduler from being updated within the 31-day alert frequency. Id. at 7.

**379- Finding: These incidents indicate a weakness in PG&E's surveillance testing program.**

380- PG&E claims that these events do not suggest a problem in its surveillance testing program. PG&E claims that the problem lies, rather, with personnel errors. Tr. at 1152. The Licensing Board finds, however, that these documents cite multiple incidents in which PG&E has failed to perform surveillance tests when the equipment was in an alert condition. Taken together with numerous other instances of missed surveillances (See discussion regarding Inadequate/Improper Surveillance in the General Findings.), these incidents establish a repetitive pattern which indicate the presence of a programmatic weakness in PG&E's maintenance and surveillance program.

**381- Finding: At least one of these incidents involved the failure of barriers designed to prevent this type of error.**

382- We also find that the first incident regarding the 8/21/91 STP test on the ASW pump involved multiple personnel errors in the same maintenance task, thus implicating the adequacy of PG&E's maintenance program to prevent such errors. In that incident, the employee responsible for conducting the test failed to recognize that the data was incorrect. MFP Exhibit 78 at 6. In addition, the shift foreman "failed to recognize that the wrong pump curve was attached to the data package," despite the fact that "the unit designation was clearly marked on the pump curves." Id. Thus, two different individuals with responsibility for this task reviewed the same test results and failed to recognize that the wrong data was being used. We find that the shift foreman's failure to detect the first error is part of a pattern of multiple personnel errors that we have seen in other instances, and which demonstrates a programmatic deficiency in PG&E's maintenance and surveillance program.

IN-SERVICE PROMPT TEST DATA QUESTIONABLE

MFP Exhibit 81: NCR DCO-92-TN-N055 (3/1/93)
MFP Exhibit 82: PG&E reply to NOV in NRC IR 92-27 (11/25/92)

Transcript pages: 1153-1159

383- STP P-6B implements ASME section XI requirements for the steam-driven auxiliary feedwater (AFW) pump by starting the AFW pump at least once every 31 days. This test includes taking vibration data and verifying that vibration velocities are within the limits in volume 9 of the plant manual. On 1/2/92, PG&E issued a revision of STP P-6B. This revision incorporated a typographical error in a diagram in the procedure. The procedure incorrectly showed data point #3 to be on top of the pump casing over the discharge of the pump, instead of on top of the bearing cap. Subsequently, ten tests on Unit 1 and eleven tests on Unit 2 had been performed with the incorrect diagram in the procedure. NCR DCO-92-TN-N055 (3/1/93), MFP Exhibit 81 at 3,4.

384- An NRC inspector noted that the diagram error in the STP called into question the validity of the vibration data collected while the diagram was incorrect. He believed that there was sufficient scatter in the data points such that the data could have been taken from the wrong spot. Furthermore, the error in the procedure had not been documented on an AR, and no formal engineering evaluation of AFW pump operability was done. Id. at 4.

385- An additional issue in the test performance was that the blue dots marking the exact locations for the proper positioning of the vibration probe were missing or painted over. The missing or painted-over dots were considered to potentially affect test repeatability. The NRC inspector "questioned several operators, who indicated that they would follow the procedure and take data where the diagram indicated." Id. at 4,5.

386- On 10/30/92, NRC issued Inspection Report 92-27, which cited PG&E for a Level IV Violation involving PG&E's failure to initiate an AR to identify the problem of test procedure STP P-6B, and PG&E's failure to evaluate the potential impact of earlier surveillance tests (performed with incorrect instructions) on the operability of safety-related pump 2-1. PG&E agreed with the violation. PG&E reply to NOV in NRC IR 92-27 (11/25/92), MFP Exhibit 82 at 3.

**387- Finding: This incident indicates a weakness in PG&E's surveillance testing program.**

388- PG&E repeatedly dismisses the idea any significance placed on the diagram error in the STP, the missing blue dots or the engineer's failure to write an AR to document the discovery of the discrepancies. PG&E claims that the diagram is "just a general aid" for the operators (Tr. at 1156); the blue dots were "another aid" (Tr. at 1158); and the engineer's failure to initiate an AR "had nothing to do with the performance of the test" (Tr. at 1156).

389- The Licensing Board disagrees with PG&E's conclusions as to the significance of these discrepancies. The Board finds this incident to be a matter of concern because multiple problems were identified with the performance of <u>one</u> testing procedure. Additionally, these problems were not identified in a timely manner. The incorrect diagram was issued early in January of 1992 and was not discovered for nearly nine months. MFP Exhibit 81 at 5. The Board finds that, taken together with the many other deficiencies we have found in PG&E's surveillance activities, this event further demonstrates a significant weakness in PG&E's surveillance testing program. See discussion in General Findings regarding Inadequate/Improper Surveillance.

HOLD DOWN MOTOR BOLTS ON CENTRIFUGAL CHARGING PUMPS

MFP Exhibit 83: NCR DC1-92-MM-N033 (2/24/93)

Transcript pages: 1160-1173

390- The centrifugal charging pumps (CCPs) perform a safety function by injecting cooling water into the core and primary loop under certain accident conditions. The charging pumps also provide RCP seal injection flow.

391- On 7/1/92, during a preventative maintenance activity on CCP 2-1, PG&E found several discrepancies on the motor hold down bolts. Further investigations identified deficiencies in the motor hold down bolts in the other three CCPs. The problems included unmarked bolts, bolts machined down to their root diameter, washers which had elongated holes and washers that were stacked. Other bolts were overtorqued to 275 ft/lbs. NCR DC1-92-MM-N033 (2/24/93), MFP Exhibit 83 at 2-4. PG&E later determined that the shear strength of the CCP joint was reduced, although PG&E believed this was compensated for by the available margin in the seismic qualification of the CCP. Id. at 5.

392- PG&E determined that during the original plant equipment procurement, procurement specification and vendor supplied information regarding the configuration of motor/pump hold down bolt connections for skid mounted equipment was inadequate. Id. at 1.

**393- Finding: PG&E's maintenance and surveillance program failed to identify the discrepancies on the hold down bolts for the safety-related charging pumps in a timely fashion.**

394- The discrepant motor hold down bolts on the CCPs were obtained in the initial procurement for the plant in the 1970s. Tr. at 1162. Yet, these deficiencies were not identified until July of 1992. MFP Exhibit 83 at 1.

395- As conceded by PG&E, the elapse of such a long interval before these discrepancies were found is due in part to inadequacies in PG&E's maintenance program. PG&E found that a contributory cause of this event was that following the procurement of these parts, maintenance practices "were not clear/controlled in this area (i.e., hold down bolt configuration/installation)." Id. at 5. Had these procedures been more clear, the irregularities could have been discovered in earlier maintenance activities.

396- PG&E also found that another contributory cause lay in its failure to implement Westinghouse technical bulletin 86-07. Id. According to the TRG, this "resulted in the failure to identify this problem at an earlier date." Id. at 20.

397- We also note that in 1986, the NRC had issued NRC Information Notice 86-25 which addressed traceability and control of material and equipment, particularly fasteners. The NRC had found several instances of lack of traceability and loss of material control on fasteners installed in various nuclear power plants. These fasteners included equipment mounting bolts, nuts, studs and washers installed on safety related equipment. MFP Exhibit 83 at 13.

398- The NCR on this event acknowledged that a potential problem with bolting was found in certain locations in 1985. Id. at 17.

**399- Finding: PG&E's maintenance and surveillance organization has paid inadequate attention to the materials and installation of fasteners and hold down bolts for safety related equipment.**

400- We are disturbed to find that DCNPP operated until the discovery date in 1992 with improperly installed CCPs. Although PG&E ultimately concluded that the CCPs could withstand an accident, the improper installation nevertheless reduced the margin of safety. Id. at 5. PG&E claims that this is a problem with procurement and not maintenance. Tr. at 1161. However, by PG&E's own admission, the installation discrepancies could have been corrected earlier if PG&E's maintenance procedures for the CCPs had been more clear; and if PG&E had implemented Westinghouse Technical Bulletin 86-07.

401- In its NCR regarding this event, PG&E listed four previous events in which PG&E discovered that vendors had supplied material that did not conform to the purchase order. These are described in NCR DC1-86-TI-N082; NCR DC1-86-TI-N083; NCR DCO-86-PG-N090; and NCR DCO-90-EN-N007. MFP Exhibit 83 at 10-12. See also Tr. at 1163-1170. These events, dating from 1986 to 1990, make it clear that PG&E has a real and ongoing problem with the discovery of material discrepancies or improper installation in procurement. PG&E is wrong in attempting to cast this issue as related entirely to procurement problems of the past rather than today's maintenance. Tr. at 1166-67. It may be that these problems should have been identified and corrected when the equipment was installed. However, once the equipment is installed, the maintenance program becomes responsible for assuring its operability. Under these circumstances, in which PG&E is on notice that inspections conducted during operation have not been adequate to identify discrepancies in material or installation, PG&E should have the means to ensure that these installations are correct. It certainly should not have taken from initial installation in the 1970s until 1992 to discover that a safety-related pump had been installed improperly, with a resultant decrease in the safety margin. See also General Findings for discussion regarding Failure or Unreliability of Important Safety Systems.

REACTOR COOLANT SYSTEM LEAKAGE

MFP Exhibit 84: NCR DC2-91-MM-N069 (2/2/93)
MFP Exhibit 85: LER 2-91-004-00 (9/16/91)

Transcript pages: 1176-1189

402- On 8/13/91, STP R-10C was performed and calculated an unidentified leakage rate from the Reactor Coolant System (RCS) of 1.4 gpm, which is in excess of the NRC license limit of 1.0 gpm. A review of the previous leak check surveillance identified a calculation error; the previous leak check underestimated the actual leak rate and this resulted in a violation of TS 3.4.6.2. An unusual event was declared. NCR DC2-91-MM-N069 (2/2/93), MFP Exhibit 84 at 1.PG&E filed a Licensee Event Report regarding this incident. LER 2-91-004-00 (9/16/91), MFP Exhibit 85.

403- The leakage was identified as originating in the Charging Subsystem of the Chemical Volume Control System (CVCS). The Charging Subsystem returns coolant to the RCS during normal plant operations following chemical treatment by the CVCS. On 8/31/91, Unit 2 was shutdown for a one week early start to the fourth refueling outage due to an increase in the unidentified RCS leakage from 0.78 gpm to greater than 0.9 gpm. MFP Exhibit 84 at 3.

404- On 9/2/91, insulation was removed from the normal charging line and leakage was identified at the body-to-bonnet joint of valve CVCS-2-8378B, the first-off check valve. In-place inspections showed that bonnet stud degradation had occurred and two of the twelve studs had failed with one more close to failure. Id.

405- Inspection of the alternate charging line check valves showed a similar leak on the bonnet gasket of the first-off check valve, CVCS-2-8378A. The evidence of leakage was similar but not as advanced. One stud had failed and three were degraded severely. The studs showed material degradation at the base of the stud where it enters the valve body. Id. at 3,4. "To date, five valves have been found with evidence of leakage." Id. at 24.

406- Failed components included the B7 bolting of the body-to-bonnet connection of primary systems valves with insufficient installation torque. Id. at 20.

407- PG&E attributed the root cause of the CVCS leakage to a loss of joint preload due to a combination of:

1. low bolting torque;
2. a low resiliency gasket;
3. thermal cyclic fatigue.

Current vendor recommendations include a "Flexicarb" gasket with an increased torque value to better allow for thermal cycling. The service environment of these valves provided for thermal cycling (STPs and letdown isolation) which accelerated joint relaxation. Joint relaxation led to leakage which, in the presence of relatively low temperatures and B7 (carbon steel) bolting material, promoted boric acid attack and stud wastage. MFP Exhibit 84 at 8-10.

408- It has been suggested that a small gasket leak developed, possibly aggravated by thermal cycling of the valve. The small leak initiated stud degradation through steam erosion or boric acid wastage or a combination of the two. The weakening and eventual failure of the studs relieved the gasket compression and resulted in a progressively increasing leak rate. Id. at 3.

**409- Finding: Despite industry communications and knowledge of the materials and the environment in which these check valves were operating, PG&E failed to establish an effective surveillance program that would have prevented/detected this extensive degradation and leakage.**

410- PG&E has already received numerous NRC and industry reports regarding the problem of boric acid corrosion on carbon steel bolts, i.e., NRC Information Notice 86-108, Supplement 2, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion;" NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants;" INPO SOER 84-5: "Bolt Degradation or Failure in Nuclear Power Plants;" INPO SER 35-87, "Non-isolable Reactor Coolant System Leak." Id. at 20,21.

411- Yet, despite this information, "there was no Mechanical Maintenance program for periodically monitoring the tightness of bolted connections and retorquing those joints which have relaxed with time." Id. at 10. "The PM program had not yet provided for a periodic retorquing of threaded fasteners." Id. at 9. PG&E has acknowledged that in order to do a retorquing, one must remove the bolts, take off the load on the bolts and then retorque them. It is very possible that preventive maintenance could have detected this leakage if it had provided for periodic retorquing. Tr. at 1183.

412- No current information is available for the condition of the Unit 1 valves (Tr. at 1182), but the materials used are the same as those on Unit 2. The potential agents to cause degradation are also present. Additionally, maintenance history for the Unit 1 charging line check valves shows that "the valves have not been retorqued or have not had studs or gaskets changed since initial installation. The bonnet studs would be expected to be B7 material torqued to the 83 ft-lb value which was in effect at that time and with original flexitallic asbestos gaskets." MFP Exhibit 84 at 4.

413- The Licensing Board concludes that PG&E's maintenance and surveillance organization was negligent in its obligation to detect degradation of equipment before it became self-evident. The previous NRC and industry communications regarding the problem should have been sufficient to inspire PG&E to proactively initiate thorough inspections and preventative maintenance on these valves. Rather, PG&E reacted to a situation that it should have been able to predict and avoid.

**414- Finding: The effectiveness of PG&E's corrective action to prevent recurrence is questionable.**

Bolt Replacement:

415- PG&E has noted that the root cause of this event "cannot be eliminated with existing technology, however, the programmatic corrective actions developed will minimize the probability of future unidentified reactor coolant system leakage due to degraded carbon steel bolted joints." MFP Exhibit 84 at 10.

416- PG&E claims that it has eliminated the problem with the corrosion of the bolts because carbon steel bolts have been replaced with stainless steel bolts; they are not subject to boric acid corrosion. Tr. at 1184. Yet, it remains unclear as to whether some or all of these bolts have been replaced. "Although there is no written instruction or tracking mechanism, B7 bolting in boric acid service valves is being replaced on in-service valves as well as newly procured valves before they are installed. At this time (October 24, 1991) there is no commitment to time-table to complete replacing B7 bolting." MFP Exhibit 84 at 19. This statement was not changed when the NCR was updated on 2/2/93.

417- The NCR further notes that

> a program has been developed... for replacing bolting on valves that now have B7 bolting that should be replaced with 630 SS. A list of all bolted connections in boric acid service has been developed for an inspection plan for 1R5. The remainder of the bolted connections not addressed in 2R4 will be taken care of during 2R5. Id. at 1.

This program to replace B7 bolting is neither an NRC nor a CMD commitment. Id. at 18,19.

418- As a prudent action (not required), PG&E intends that a "comprehensive program will be developed to identify which bolted connections in boric acid service in containment will be part of the inspection/replacement program, i.e. those bolted connections which are most sensitive to boric acid wastage." MFP Exhibit 84 at 19,20.

Retorquing:

419- Again, it remains unclear as to specifically what corrective actions PG&E has committed to make and when. The recommended action by NECS to develop a PM program for retorquing bolted connections is being considered a prudent action (not required). Id. at 18. Also included as prudent actions: "A valve bonnet bolting retorque initialization program will be developed" and "a future program for inspection-retorquing-replacement of bolted connections in boric acid service will be developed for B7 bolting in containment." Id. at 19. As of 2R4, only "some" valve bolting torque was "checked and verified and/or reestablished." Id. at 1.

420- The Licensing Board finds PG&E's corrective actions vague and indefinite. PG&E has now recognized the problems, yet has failed to act with commitment; this is clearly an inadequacy in PG&E's maintenance and surveillance program at DCNPP.

REACTOR CAVITY SUMP WIDE RANGE LEVEL CHANNEL 942A INOPERABLE

MFP Exhibit 86: NCR DC2-91-TI-N096 D8 (1/25/93)
MFP Exhibit 87: LER 2-90-010-01 (7/30/91)
MFP Exhibit 88: NRC IR 92-01 (2/28/92)
MFP Exhibit 89: PG&E reply to NRC NOV in IR 92-01 (3/30/92)

Transcript pages: 1189-1202, 2198-2203
PG&E Testimony: 93-95
NRC Testimony: 11,12

421- Containment reactor cavity sump wide range level channels are post-accident instrumentation used to provide quantitative data to the Safety Parameters Display System (SPDS) about the water level inside the containment structure. "These data are used to verify the occurrence of a loss-of-coolant accident (LOCA) and to evaluate plant conditions to assure proper response to an accident." LER 2-90-010-01 (7/30/91), MFP Exhibit 87 at 5.

422- A normal channel indication of 0 is difficult to distinguish from a failed channel indication of slightly below 0. But the SPDS provides notice of a failed channel by displaying a question mark when there is a problem with input data. Id. at 2. A blue flashing path means that the channels supplying data to SPDS for that logic path are not operable. PG&E reply to NRC NOV in IR 92-01 (3/30/92), MFP Exhibit 89, Enclosure at 1.

423- On 10/22/91, an NRC inspector noticed that reactor cavity sump wide range level channel 942A was out of tolerance, and it was declared inoperable. I&C discovered that it had been inoperable (and undetected) since 10/10/91, failing to meet TS specifications. On 10/23/91, the NRC inspector again identified that channel 942A indication had dropped. Channel 942A indication shifted low an additional nine times over the period of 11/91 through 3/92. NCR DC2-91-TI-N096 D8 (1/25/93), MFP Exhibit 86 at 1. PG&E was unable to discover the root cause of the channel failure. MFP Exhibit 87 at 2,8. A Level IV violation was issued by the NRC for this incident. NRC IR92-01 (2/28/92), MFP Exhibit 88, NOV.

424- A previous similar event had occurred in 1990 in which channels 942A and 943B were both inoperable from 8/21/90 until 11/6/90. The operators and I&C personnel involved did not understand the meaning of the blue flashing path on the SPDS display screen and were not aware of the failed channels. MFP Exhibit 89, enclosure at 2. PG&E determined the root cause of the failure of channel 943A in 1990 to be normal wear-out of the power supply fuse. The root cause for the failure of channel 942A in 1990, however, could not be determined. MFP Exhibit 87 at 7.

**425- Finding: PG&E's previous corrective actions failed to prevent recurrence.**

426- Corrective measures taken after the events of 1990 involved additional training on the SPDS. However, "the recurrence of the violation of TS 3.3.3.6.a {in 1991} identified that the corrective action to train the operators was not adequate to prevent recurrence of the event." MFP Exhibit 87 at 7. "This corrective action should have prevented the event that is the subject of this current NCR." MFP Exhibit 86 at 15.

427- The NRC commented that

> the inspection identified a failure of Unit 2 to comply with a Technical Specifications action statement in October 1991, due to an undetected failure of a reactor cavity sump wide range level channel. A similar failure occurred in 1990 and was not detected for over two months. We conclude that your corrective actions for the 1990 surveillance program were inadequate to detect failed Technical Specification equipment. You appear to have missed an opportunity to have precluded the October 1991 undetected failure. MFP Exhibit 88, cover letter.

428- The opportunity that PG&E missed in 1990 was that it did nothing to ensure that operators would look at the SPDS; instead, it just trained operators to understand the SODS signals if they did look. MFP Exhibit 89 at 2. But, as PG&E testified in the hearing, "just looking at the recorders" during a surveillance test is not enough. The SPDS must also be utilized. Tr. at 1193,1194. After the 1990 event, PG&E nevertheless failed to modify the STP to require a daily check for indications of channel problems. The STP was not modified until after the 1991 events. MFP Exhibit 89 at 2.

**429- Finding: The SPDS is not maintained in a sufficiently reliable condition to provide reasonably accurate indications of sump level.**

430- The Board finds that PG&E does not maintain the SPDS in a sufficiently reliable condition to detect reactor cavity sump level. The record shows that there are multiple levels of uncertainty, caused by the unreliability of the system. First, the reactor cavity sump level channel indicators are subject to intermittent failure, for causes that still remain unknown. As the NRC testified, "Failed indicators are not uncommon." Tr. 2199. Thus, they cannot be relied on to give consistently accurate information. It is also difficult to tell when the channel indicators are not functioning, because a normal channel indication of 0 is almost indistinguishable from a failed channel indication of slightly below 0. The SPDS supposedly compensates for this problem by flashing a question mark or blue signal when there is a problem. However, in January of 1993, the PG&E TRG reported its intent to investigate the fact that "It seems that question marks are not appearing on the screen when they are supposed to." MFP Exhibit 86 at 21. We also note that the entire SPDS is not seismically qualified. Tr. at 1197. Thus, it cannot be relied on at all during an earthquake. These multiple levels of uncertainty in the maintenance of the SPDS system fatally undermine our confidence that this safety function can be performed with an adequate level of assurance.

**431- Finding: This issue is relevant to maintenance and surveillance.**

432- PG&E claims in proposed finding M-A110 that this issue is unrelated to maintenance. On its face, the claim is absurd. The incidents described above relate to PG&E's failure to maintain a safety indicator in an operable condition, and its failure to monitor the status of the equipment so that a failure would be detected. PG&E appears to find significance in the fact that the NRC's enforcement action emphasized the operators' lack of awareness of the meaning of the SPDS signals. If this is an oblique argument that the issue is not maintenance related because the errors were not made by maintenance personnel, we reject it. The fact that some monitoring is performed by operators rather than maintenance personnel does not negate the relevance of that monitoring activity to the adequacy of maintenance and surveillance at DCNPP. If DCNPP operators who are responsible for monitoring the SPDS are unable to detect when a safety instrument is failing and requires replacement or repairs, then there is a lack of reasonable assurance that the plant is being monitored and maintained adequately.

433- PG&E also argues that this instance does not represent a maintenance problem "because failed indicators are not uncommon" and "It can be extremely difficult to pinpoint the exact cause of the failure." Proposed finding M-A114. This seems to be an argument that if PG&E is not capable of preventing the equipment from failing or understanding why it failed, the failure is not related to maintenance. However, we do not apply a "best efforts" or "feasibility" standard to the question of whether PG&E's maintenance and surveillance program is adequate to protect the public health and safety. The test is an objective one: whether the public health and safety is protected adequately by maintenance and surveillance at DCNPP. Thus, the question is not whether some equipment failures are common and difficult to detect, but whether safety is adequately protected despite the allegedly inherent inadequacy of the maintenance and surveillance program to prevent or detect them. Accordingly, the incidents described above implicate the adequacy of PG&E's maintenance and surveillance activities to protect the public.

DCM SURVEILLANCE/MAINTENANCE REQUIREMENTS

MFP Exhibit 90: NCR DCO-93-TN-N006 (2/12/93)
PG&E Exhibit 23: NCR DCO-93-TN-N006 (8/23/93)

Transcript pages: 1202-1211

444- During an audit, a generic problem regarding implementation of Design Criteria Memorandum (DCM) Category I surveillance/maintenance requirements was identified. Contrary to the requirements of NECS E3.2 and DCM S-21, no surveillance test exists to provide verification of the emergency diesel generator fuel oil day tank low level switch transfer pump start signal. Additionally, PG&E found that other DCM functional requirements may not be addressed in existing surveillance/maintenance requirements. NCR DCO-93-TN-N006 (2/12/93), MFP Exhibit 90 at 2.

445- PG&E is continuing to review the consistency between the maintenance and surveillance programs and the design documents for all Category I devices. It expects to complete this review by the end of 1993. Tr. at 1208,1209.

**446- Finding: The discovered discrepancies in PG&E's design documents and its maintenance procedures indicate a weakness in PG&E's surveillance testing program.**

447- PG&E admits that "it is important that the ... design documents reflect what's in the maintenance and surveillance programs." Tr. at 1207. Indeed, information about the design of the plant had to be used to develop the maintenance program in the first place. Tr. at 1209,1210. Yet, this is PG&E's first thorough review to verify that design and maintenance programs are, in fact, consistent. The PG&E TRG noted that a possible root cause of the problem is the fact that "the plant has no program for DCM review." PG&E Exhibit 23 at 7.

448- We believe that consistency between design and maintenance is fundamental to an adequate maintenance program. Apparently, the last time this issue was reviewed was during construction. So far, PG&E has had no operational program for ensuring consistency between design and maintenance. PG&E has correctly undertaken to complete a design documentation review which is intended to address this problem. Indeed, the fact that PG&E has already found discrepancies between the design and maintenance for specific components, such as the testing of the diesel generator fuel oil day tank low level switch transfer pump start signal, provides tangible confirmation of the need for this review.

449- Given the importance of the design/maintenance review, it is essential that PG&E complete it and make all necessary changes before its license can be extended. The review should include all Class 1 equipment (now scheduled for completion by the end of 1993, Tr. at 1209), and Class 2 equipment, for which we are unaware of a completion date. In this regard, we note our concern that the TRG found "there is some confusion as to PG&E's commitments to the NRC regarding this matter." PG&E Exhibit 23 at 8.

**450- Conclusion:** Accordingly, the Board cannot find that PG&E has demonstrated the adequacy of PG&E's maintenance program with respect to its consistency with the plant's design, unless and until the design documentation review is completed.

SNUBBER AT PIPE SUPPORT

Exhibit 91: NCR DC1-92-MM-N021 (2/12/93)
Exhibit 92: LER 1-92-016-00 (11/30/92)

Transcript pages: 1211-1222

451- On 5/14/92, during a structural inspection walkdown, PG&E discovered a damaged snubber at pipe support 1-171SL on a main feedwater flow control bypass line for Steam Generator 1-1. NCR DC1-92-MM-N021 (2/12/93), MFP Exhibit 91 at 1. The function of a snubber is to allow a line to move smoothly if there's any shaking - "mainly for a seismic event." Tr. at 1213. Although this particular snubber does not serve a safety function, these snubbers are used in safety-related applications at DCNPP. Tr. at 1214,1215.

452- Investigation by PG&E concluded that the snubber had locked in place during plant operation. Subsequent compressive thermal loading that occurred during system cooldown as a result of a plant trip caused the snubber to buckle. MFP Exhibit 91 at 1.

453- The snubber is an Anchor Darling 501L with a 10" stroke. PG&E determined that the failure of an internal part (verge wheel) had caused the snubber to lock in place. An evaluation of the failed verge wheel conducted by TES determined that the failure was due to stress corrosion cracking (SSC). Id. In order for this condition to occur, three factors must be present:

1. Material: the verge wheel is made from 440C stainless steel, heat treated to high strength level. This material is susceptible to SCC when exposed to a contaminated environment and high tensile stress.
2. Environment: the snubber was located outdoors, in the coastal atmosphere which is humid and contains chloride salts. Water entered the snubber, as evidenced by the rust found on some inside components which include the verge wheel. Chloride in solution can cause stress corrosion cracking in high strength steels.
3. Stress: the pinion hole in the failed wheel was found to be smaller than the dimension specified by Anchor

Darling, and the diameter of the pinion was found to be at the maximum tolerance specified by Anchor Darling. This resulted in a large amount of interference which created a high hoop (tensile) stress in the wheel. The stresses in the failed wheel were calculated to be 250% higher than the maximum stresses expected based on the manufacturer's specificiations.

LER 1-92-016-00 (11/30/92), MFP Exhibit 92 at 3,4.

454- **Finding: PG&E's maintenance and surveillance program failed to prevent or detect the presence of the defective snubber until it failed.**

455- PG&E claims to have a program that inspects and tests snubbers, but this program does not inspect the internal components. Tr. at 1218. PG&E has further testified that the corroded components in this particular snubber could not have been detected without disassembly. Tr. at 1219. The Board is concerned regarding the high number of equipment defects which PG&E claims cannot be detected with ordinary surveillance measures. See our General Findings regarding Manufacturing Deficiencies and Internal Defects.

GAS DECAY TANK SURVEILLANCE MISSED

MFP Exhibit 95: NCR DC1-92-2C-N041 (2/2/93)
MFP Exhibit 96: LER 1-92-017-00 (10/9/92)

Transcript pages: 1223-1227

456- Radiation monitors are installed on each Gas Decay Tank (GDT) to provide alarms in the auxiliary building control room and the main control room in the event that the quantity of radioactivity and the GDTs approaches the limit of 10,000 curies of noble gas (as XENON-133 equivalent). NCR DC1-92-2C-N041 (2/2/93), MFP Exhibit 95 at 6.

457- TS 4.11.2.6 requires that the quantity of radioactive material contained in each GDT shall be determined to be within the limits set forth in TS 4.11.2.6 at least once per 24 hours when radioactive materials are being added to the tank. Id. at 2.

458- On 10/12/92, the time limit for the surveillance was exceeded when a technician failed to perform the required GDT within the 24 hour time limit. Id.

459- The root cause of this event was due to inadequate instructions. The instructions on the checklist specified that the surveillance was to be performed daily and did not specify that the surveillance was to be performed at least once per 24 hours as required by TS 4.11.2.6. LER 1-92-017-00 (10/9/92), MFP Exhibit 96 at 4.

460- Six previous similar events were noted: LER 1-85-008-00 addressed the failure to perform TS required surveillance. LER 2-86-027-01 addressed the missed surveillance of a plant vent particulate sample. LER 1-86-002-00 addressed a surveillance required by TS not performed. LER 1-87-026-00 addressed a missed surveillance for sampling an analysis of reactor coolant system chloride and fluoride concentrations.

LER 1-88-001-00 addressed the failure to perform plant vent air sampler flow estimate. LER 1-90-013-00 addressed a missed reactor coolant system sample. MFP Exhibit 95 at 9-11.

**461- Finding: This incident is part of a pattern of missed surveillance tests, and thus indicates a weakness in the surveillance testing program at DCNPP.**

462- Inadequate instructions enabled the technician to miss an important surveillance. The Licensing Board finds that this incident, and the others cited by SLOMFP, demonstrate a weakness in PG&E's surveillance testing program at DCNPP. See discussion in General Findings regarding Inadequate/Improper Surveillance.

SEISMIC CLIPS NOT INSTALLED

MFP Exhibit 98: NCR DC1-92-OP-N062 (1/27/93)

Transcript pages: 1240-1249

463- The reactor trip and bypass breakers are provided with seismic clips. The primary purpose for these clips is to maintain breaker cell position during a seismic event, in order to ensure that the features provided by the circuit breaker auxiliary switches and cell interlock switches function properly during and after the event. NCR DC1-92-OP-N062 (1/27/93), MFP Exhibit 98 at 2.

464- On 12/3/92, Instrument and Control (I&C) personnel discovered that the Unit 1 reactor trip and bypass breakers did not have the required seismic clips installed. A review of operating records indicates that the clips were not installed when the reactor trip and bypass breakers were made available for service on 11/3/92 during unit restart from 1R5. Id. at 2. Thus, during this one month period, had a reactor trip been necessary due to a seismic event, it is possible these breakers would not have activated as required.

465- PG&E's NCR reviewed the previous status of the clips, and reported that on October 27, 1992, the Reactor Trip and Bypass Breakers were left in the "Racked Out" position. "The seismic clips were not installed on the Reactor Trip breakers, since the breakers must be racked in for installation, and were apparently loosely installed on the bypass breakers at this time." Id. at 3.

466- According to PG&E, "the system remained in this configuration until November 11, 1992, when Operations performed STP M-18 and STP M-22." The performance of STP M-18 "requires that all combinations of Reactor Trip and Bypass breaker configurations be tested. The operator noticed that the seismic clips were not installed on the trip breakers, and were loosely installed on the bypass breakers." Id.

> Since the operator's past experience was that the Instrument and Control technicians installed and removed the seismic clips, he notified the Shift Foreman that the clips were installed on the bypass breakers and requested assistance from I&C or clarification on how he was to proceed. The Shift Foreman instructed the operator to

remove the clips from the bypass breakers and perform the STP, and he would make arrangements for I&C to install the clips following the test. The shift foreman made an entry in his personal notepad as a reminder to contact I&C to arrange for the clips to be installed. Id.

The Operator completed STP-M-18, which left the system in the normal, at-power configuration (trip breakers racked in, bypass breakers racked out). STP M-22A was also performed, but it required no further manipulation of the reactor trip or bypass breakers. The Shift Foreman and Licensed Operator were not concerned about the seismic clip installation since the trip breakers were not required at the time, and normal, at-power testing routinely removed the seismic clips from both bypass breakers. The note to request I&C to install the seismic clips was overlooked due to the normal Mode 4 preparation activity in the control room, and was forgotten. Id. at 3,4.

The reactor trip breakers remained in their normal configuration without the seismic clips installed until December 3, 1992, when I&C noticed they were not installed, prior to performing another STP. The Shift Foreman then concluded that both reactor trip breakers were inoperable. Id. at 4.

**467- Finding: No procedural controls existed to ensure that the seismic clips are reinstalled after routine testing.**

468- PG&E found that the root cause of this event was "a programmatic problem in that no procedural or programmatic controls were in place to ensure that the reactor trip and bypass breakers were properly secured with seismic clips..." MFP Exhibit 98 at 7. "The procedures that were in place in modes 5 and 6 did not assure that the clips were put in place prior to starting up the plant." Tr. at 1241. PG&E also testified that "there was some confusion in this event... between ops and I&C as to who should install the clips..." Tr. at 1245.

**469- Finding: Corrective action taken by PG&E for a previous similar event failed to prevent this incident.**

470- A similar event, which occurred four years earlier was documented in NCR DCO-88-EM-N005. This NCR was initiated following discovery that the seismic clips had not been installed per design following initial plant start-up. "Corrective actions for this NCR included revising operating procedures to include seismic clip installation during routine testing. This corrective action failed to prevent the present event since no actions were taken to ensure that the configuration was proper during subsequent plant start-ups." See MFP Exhibit 98 at 11 (emphasis added).

**471- Finding: Other factors contributing to the occurrence of this event demonstrate weaknesses in PG&E's surveillance program.**

472- PG&E found that one of the contributory causes of this event was inadequate communication, due to inattention by the operation's shift foreman. Following performance of STP M-18, the operator performing the test - who had no knowledge of the operability requirements associated with the seismic clips - consulted with the shift foreman concerning the need to have I&C personnel install the seismic clips. The shift foreman noted this item, but it was overlooked and no request to I&C was ever made. Id. at 7. This poor communication between more than one department which is responsible for a surveillance or maintenance activity is a recurrent problem at

DCNPP, and reflects an unacceptable weakness in PG&E's maintenance and surveillance program. See discussions in General Findings regarding Lack of Communication and/or Coordination.

CONTAINMENT FAN COOLING UNIT (CFCU) BACKDRAFT DAMPERS

MFP Exhibit 100: NCR DCO-92-MM-N022 (1/4/93)
MFP Exhibit 101: LER 1-92-023-00 (11/20/92)
MFP Exhibit 102: NRC IR 92-17 (5/8/92)
MFP Exhibit 103: LER 1-91-019-01 (6/5/92)
MFP Exhibit 104: NCR DCO-92-MM-N007 (2/12/92)
MFP Exhibit 140: NRC Management Meeting, Report 92-3 (4/16/92)
PG&E Exhibit 24: PG&E Reply to NOV in NRC IR 92-17 (7/20/92)
NRC Exhibit 1: NRC Enforcement Conference 92-19 (6/18/92)
NRC Exhibit 2: NRC NOV from IR 92-17 (6/19/92)

Transcript pages: 1249-1262, 2209-2226
PG&E Testimony: 88,89
NRC Testimony: 7-9

473- The Containment Fan Cooling Units (CFCUs) are used to cool the containment atmosphere and equipment located in the containment building during normal operation. In a LOCA, they serve to limit the pressure peak in containment in conjunction with the containment spray system. NRC Ts. at 7.

474- Since at least 1986, PG&E has had numerous and significant problems with the maintenance of the CFCU backdraft dampers. PG&E and the NRC addressed these problems in their testimony. Mary Miller, Senior Resident Inspector, called the problem "their biggest black mark in the past few years." Tr. at 2214. But the "performance of the CFCUs and the various surveillances associated with it are not an issue anymore to my office's opinion." Tr. at 2212.

475- Based on the testimony and the record documents regarding the CFCU backdraft dampers, the Board makes the following findings:

**476- Finding: CFCU maintenance problems have been long standing.**

477- DCNPP has experienced a series of CFCU maintenance problems involving missing counterweight assemblies or lacking locknuts, counterweights installed too tightly or not installed or functioning as designed, loose or broken bolts, reverse rotation of dampers, holes elongating, failure of the dampers to close, rust, dirt buildup in the CFCU coils (NRC IR 92-17 (5/8/92), MFP Exhibit 102 at 1-7), and cracked blades (LER 1-92-023-00 (11/20/92), MFP Exhibit 101).

478- The NRC found that these deficiencies "appear to be indicative of longstanding problems" with the containment ventilation system. MFP Exhibit 102 at 12. Indeed, the 7-page chronology provided in NRC Inspection Report 92-17 shows that CFCU backdraft damper problems date to at least 1986 (Id. at 2). Moreover, faulty operation of backdraft dampers is documented as far back as 1981. NCR DCO-92-MM-N007 (2/12/92), MFP Exhibit 104 at 31. (1992 NCR lists six "Previous Problem Reports" addressed in NCRs between 1981 and 1985, regarding "stuck-open backdraft dampers on CFCUs 2-1 and 2-2.")

**479- Finding: PG&E did not take effective or timely action to correct problems with the CFCU backdraft dampers.**

480- Although PG&E's problems with backdraft dampers had already existed for some time, PG&E did not begin to focus attention on them until early 1992, when PG&E discovered that it had been operating Unit 1 with three inoperable CFCUs since March 27, 1991 - almost an entire year. The NRC cited PG&E for four apparent Severity Level IV violations, including "failure to take appropriate corrective actions after observing reverse rotation of Unit 1 CFCUs on March 25, 1991." MFP Exhibit 102 at 2.

481- In Inspection Report 92-17, the NRC found that

> despite numerous problems over the last several years, the quality organization did not pursue the containment ventilation system, or the CFCUs in particular, as an area requiring further attention. Even after major deficiencies were found in Unit 1 (three CFCU dampers inoperable in February 1992), a comprehensive assessment of Unit 2 dampers was not initiated by QA or QC. The quality organization appeared to be following up on problems rather than identifying them.

Id. NRC IR 92-17 also noted that "the failure to promptly close Work Order C0095999 kept information from reaching the personnel who needed it. This may indicate a weakness in the timely closure of Work Packages. The inspector expressed concern that PG&E management expectations are either not clearly understood or not being implemented." Id. at 12.

482- On April 2, 1992, the NRC held a "management meeting" with PG&E which focused on "timely identification and correction of problems." Letter from R.P. Zimmerman, NRC, to

G.M. Rueger, PG&E, NRC Management Meeting, Report 92-3 (4/16/92), MFP Exhibit 140, cover at 1. The NRC concluded from the meeting that the "discussions regarding the containment fan cooler units and the main feedwater pump problems illustrate that your staff is not always resolving indications of system problems in a prompt, thorough manner. The timeliness of your corrective actions for known problems has been a past issue of concern." Id.

483- The NRC also held an Enforcement Conference on 5/19/92. K. Perkins (NRC Deputy Director, Division of Reactor Safety and Projects) stated that "Diablo Canyon had a recent history of identifying problems and then taking an excessive amount of time to address those problems in a systematic manner. Examples of previous issues that were slow to be fully addressed included sticking of valve 1FCV-95 and deficiencies with regulatory guide 1.97 instrumentation." NRC Enforcement Conference 92-19 (6/18/92), NRC Exhibit 1 at 2.

484- The NRC issued a Notice of Violation on June 19, 1992. NRC NOV from IR 92-17 (6/19/92), NRC Exhibit 2. One of the three Severity Level IV violations cited by the NRC was that, contrary to the requirements of Criterion XVI of Appendix B to 10 C.F.R. Part 50,

> In February 22, 1992, the licensee failed to correct a condition involving reverse rotation of CFCU 1-5, a condition adverse to quality. Correction of this problem could have led to the discovery of similar problems with the backdraft dampers associated with three other containment fan cooler units.

Id. at 2.

485- In a 1993 NCR, PG&E also reported that in 1988, it had noticed "an increasing number of HVAC ARs" and had established an "HVAC task force" in response. NCR DCO-92-MM-N022 (1/4/93), MFP Exhibit 100 at 14. However, the task force was ineffective: "An action plan was generated, but efforts slowly trailed off by 1990 due to budget/manpower/management support for the task force." Id.

486- PG&E's discovery of CFCU fan blade cracking also may have been untimely. On October 15, 1992, during 1R5, PG&E found cracking in the CFCU backdraft damper blades, a condition "potentially outside the design basis of the plant." PG&E attributed the root cause to "high cycle fatigue." MFP Exhibit 101 at 1. PG&E filed an LER regarding this discovery. Id. The fan blades in both units were replaced. Id.

487- PG&E claims that the cracking of the damper vanes was not reflective of a maintenance problem "because of the material that was used... and... there was vibration that caused the cracking." Tr. at 1255. But PG&E's own NCR shows that it has assigned, but not completed, a review of its question in its internal document: "Review previous maintenance history. Document why past inspections failed to identify cracking in the BD blades." MFP Exhibit 104 at 43.

488- PG&E's analysis of whether the fan blade cracking could have been discovered earlier is apparently still underway. Until we see the results of this analysis, the Board has no basis for concluding that PG&E was any more effective in detecting early signs of fan blade cracking than it was for the other CFCU problems discussed here.

**489- Finding: An unacceptable range of maintenance deficiencies contributed to the problems with the backdraft damper fans.**

490- On June 5, 1992, in a revised LER regarding the CFCU problem, PG&E reported its conclusion that the "root cause" of the CFCU problem was "a failure to perform proper maintenance." LER 1-91-019-01 (6/5/92), MFP Exhibit 103 at 8. Contributory causes were listed as:

> 1. Management underestimated the importance of the backdraft dampers to the overall safety function of a CFCU, and therefore did not provide for adequate maintenance. This resulted in:
>
> a. Poor planning of CFCU backdraft damper work.
> b. Inadequate work instructions.
> c. Inadequate job turnover.
> d. No Quality Control direct involvement in inspection of CFCU backdraft damper work.
> e. Inadequate Plan System and System Design engineer involvement.
>
> 2. Post-maintenance testing was not adequately implemented.
>
> 3. Missed opportunities from prior problems and observations relative to backdraft damper design and maintenance.

Id. Inadequate training and poor supervision were other causative factors identified by PG&E. PG&E Exhibit 24 at 6. Poor individual performance was another cause attributed by PG&E to its CFCU problems. One of the violations issued by the NRC was for a deficient inspection of Unit 2 CFCUs on 3/7/92 and 3/8/92. NRC Exhibit 2 at 2. The NRC found that the inspection was conducted without appropriate procedures and incorrectly concluded that CFCUs 2-2 and 2-5 were assembled correctly. Id. PG&E replied to this NOV, noting that the root cause of the deficient inspections was due to poor individual performance in that "the inspections were not thorough, erroneous assumptions were made, results of previous inspections were not made readily available, and the inspections lacked objectivity and professionalism." PG&E Exhibit 24 at 4.

491- In response to a discussion regarding the deficient inspections, J. Martin, NRC Regional Administrator, "commented that this was a troubling situation in that PG&E should have been able to send two engineers out with good instructions and be able to expect them to perform a good inspection." He expressed a concern that "multiple engineering and oversight organizations were involved but failed to identify the problems earlier. This appeared to indicate a need for more accountability and personal responsibility to ensure that equipment operated as designed." NRC Exhibit 1 at 4.

492- Thus, the CFCU problems were caused by a range of problems, including poor performance of maintenance and inspections by individuals, bad judgment, inadequate training, and inadequate coordination and supervision. As discussed below, the Board finds each of these deficiencies to be significant on its own. We also find that taken together, the existence of such a broad range of problems affecting the maintenance of a single safety system indicates a systemic breakdown. Some problems can be expected in any maintenance program. However, when maintenance fails on so many significant fronts (i.e., unsound engineering judgment, lack of training or supervision, lack of management attention), with the result that a maintenance problem is allowed to go untended for a period of years - it is a clear sign that there is something seriously wrong with the maintenance program. Our concern is elevated by the fact that many of these deficiencies are part of a pattern that is seen elsewhere in PG&E's recent maintenance history.

493- The Board's more detailed findings regarding specific maintenance deficiencies and their significance are provided below:

**494- Finding: PG&E showed poor judgment in its handling of CFCU problems.**

495- PG&E stated that the cause of "the untimely response to the identified CFCU reverse rotation problem was that management and the maintenance organization underestimated the importance of the backdraft dampers to the overall safety function of the CFCUs." PG&E Exhibit 24 at 6.

496- NRC Inspection Report 92-17 noted that "after identification of the loose counterweights in Unit 2 on January 22, 1992, it appeared that resolution efforts were focused on the evaluation and resolution of individual problems. A broad review of potential problems with the backdraft dampers was not completed until the end of April 1992. The licensee required nearly a month, from January 23, 1992 (when the Unit 1 counterweights were found to be installed too tight) until February 19, 1992, to determine that the dampers for three CFCUs were stuck in the open position. Analyses were focused on the potential effects of counterweights being too tight and not on whether the entire damper functioned properly.

498- The NRC also found that

> When broken bolts were identified on March 23, 1991 in CFCU 1-2, an engineering evaluation was not done to determine the root cause of the bolt failures. This indicated a need for a more inquisitive engineering approach to problem resolution.
>
> Even after the Unit 1 backdraft dampers were found to have major problems, the discovery of previously undetected problems in the Unit 2 dampers on April 16 clearly showed that licensee personnel did not maintain an objective and inquisitive attitude. At least five documented inspections... [incorrectly] documented that the Unit 2 backdraft dampers were properly installed and met the design drawings. MFP Exhibit 102 at 10,11.

NRC also determined that the "lack of broad focus and inability to identify the CFCU problems should be a significant concern to licensee management." Id. at 12.

499- At the management meeting that took place on 4/2/92, the NRC questioned PG&E

> regarding why indications of broken bolts on backdraft dampers in March of 1991 were not adequately followed up... Mr. Martin observed that the March 1991 failure to evaluate the broken bolt issue illustrated a lack of basic engineering instincts. Mr. Martin closed the discussion of this issue by stating that the attitude should be that if any bolts are broken, there is a problem. He restated the NRC concern that licensee management needed to communicate the right expectations

> for resolving problems to all engineering groups and to organizations performing the quality assurance functions. MFP Exhibit 140 at 2,3.

**500- Finding: Inadequate training contributed to PG&E's maintenance problems.**

501- PG&E stated that contributing factors causing the untimely response to the CFCU reverse rotation problem was "inadequate training of plant personnel regarding the identification and resolution of such problems." PG&E Exhibit 24 at 6.

**502- Finding: Activities and responsibilities of the maintenance and engineering departments were not adequately coordinated. Internal communications within the maintenance department were also poor.**

503- In Inspection Report 92-17, the NRC found that

> It appears that miscommunications occurred regarding whether all or only some of the dampers in Unit 1 had been observed to be working properly. No outside organization was critically reviewing the conclusions or bases for the conclusions regarding operability of the CFCUs. This could have assisted in identifying the miscommunications or in assuring that assumptions were promptly confirmed. MFP Exhibit 102 at 11.

The NRC also stated that

> It appears that part of the reason why the Unit 1 CFCU backdraft dampers were not installed properly was that this work was not given much supervisory attention and was considered as work to be done when personnel were available. Related maintenance procedures and work instructions also provided insufficient direction to maintenance and inspection personnel. <u>This resulted in numerous people and crews doing work, apparently without sufficient coordination."</u> <u>Id.</u> at 12 (emphasis added).

In Inspection Report 92-17, the NRC found that

> the maintenance organization attempted to resolve the problems of reverse rotation and broken bolts without the involvement of corporate or system engineering personnel. System engineers appeared to be responsible for system design and current status. Between the maintenance and engineering organizations, however, there was an absence of a broad perspective of the system's performance and the root causes of problems. PG&E management did not appear to have defined clear performance expectations for system engineers, maintenance engineers, corporate engineering, and maintenance personnel. Id., cover at 2.

Moreover,

> internal communications and attention to detail appeared to be a significant problem for Diablo Canyon. The extra washers, along with counterweights which were installed too loose or too tight, indicated that maintenance personnel did not follow the design drawings in accomplishing work. The existence of tight counterweights in Unit 2 was identified in January 1992, but was not communicated to PG&E management until April, after reverse rotation of CFCU 2-2 prompted the licensee to conduct additional inspections. Id.

504- **Finding: The CFCU problems were caused in part by numerous personnel errors and failures of judgment, resulting in the breakdown of multiple barriers which should have prevented the problems from going undetected for so long.**

505- Clearly, multiple errors were made by the maintenance personnel who were immediately responsible for the CFCUs. In addition, as discussed above, there was poor coordination between maintenance and engineering. Thus, the involvement of multiple disciplines in the maintenance of the CFCUs, which should have prevented the problems from occurring or existing as long as they did, was ineffective.

506- In addition, the QA and QC departments failed to carry out their responsibility to evaluate the situation. As the NRC found in Inspection Report 92-17, First, despite numerous problems over the last several years, the quality organization did not pursue the containment ventilation system, or the CFCUs in particular, as an area requiring further attention. Even after major deficiencies were found in Unit 1... a comprehensive assessment of Unit 2 dampers was not initiated by QA or QC. The quality organization appeared to be following up on problems, rather than identifying them. MFP Exhibit 102, cover at 2.

507- The Board concludes that the CFCU breakdown is part of a pattern in which multiple personnel barriers, intended to prevent mistakes from being overlooked or exacerbated, did not function. This demonstrates a programmatic breakdown in the maintenance and surveillance program for DCNPP.

508- **Conclusion:** PG&E and the NRC claim that the CFCU backdraft damper problem is resolved. Tr. at 2212 and 1259. We find that although PG&E may have resolved the specific technical problems related to the CFCU backdraft damper fans, we do not have grounds for finding that there is a reasonable assurance that the many maintenance deficiencies that contributed to this long standing problem have been adequately addressed. To the contrary, we find that the range of maintenance deficiencies reflected in this problem with one safety system evidence a breakdown in PG&E's maintenance program, especially in the coordination between maintenance, engineering, and QA, in the quality of supervision exercised over maintenance work, in the quality of judgment over the importance of the CFCUs and what investigative and corrective measures were warranted, and in PG&E's laxity in pursuing its problems. These many maintenance deficiencies resulted in a breakdown of the multiple barriers that are intended to detect and correct maintenance errors before they are allowed to persist or worsen. Moreover, we find that these problems are repeated elsewhere in PG&E's operation, thus reflecting programmatic deficiencies in maintenance and surveillance at DCNPP. The Board shares the concern of the NRC that although "the specific problems appear to have been technically resolved... PG&E management should address the potential for similar organizational and personal performance problems which could result in future deficiencies." Id. See also General Findings for discussion regarding Breakdown of Multiple Barriers.

CONTROL OF FOREIGN MATERIAL/CLEANLINESS/HOUSEKEEPING

MFP Exhibit 105: NRC IR 92-31 (12/11/92)
MFP Exhibit 106: NRC Diablo Canyon Shutdown Risk and Outage Management Inspection (NRC IR 50-275/92-201) (12/8/92)
MFP Exhibit 107: NRC IR 88-10 and 88-11 (6/17/88)
MFP Exhibit 108: NRC NOV in IR 88-07 (5/5/88)
MFP Exhibit 109: NCR DC2-91-TN-N102 R2 (11/18/92)
MFP Exhibit 110: NCR DC0-91-MM-N042 (5/19/92)
MFP Exhibit 111: LER 2-91-012-00 (3/5/92)
MFP Exhibit 113: PG&E reply to NRC EA 89-241 (3/12/90)
MFP Exhibit 35: PG&E Self-Evaluation of DCNPP (7/93)
PG&E Exhibit 25: PG&E reply to NOV in NRC IR 88-07 (6/6/88)
PG&E Exhibit 26: PG&E reply to NOV in NRC IR 88-11 (7/18/88)

Transcript pages: 1504-1534, 2226-2242
PG&E Testimony: 97-98

509- Whether it is referred to as foreign material, cleanliness, housekeeping, loose debris, or trash, this issue involves the control of material that can damage equipment, components or structures. The history of problems involving control of foreign material dates back as far as 1985 (MFP Exhibit 113, enclosure at 1) and has been noted as recently as December of 1992 (MFP Exhibit 106 at ii).

510- Some of the problems have involved loose debris in containment (MFP Exhibits 105,109,111), foreign material in the reactor coolant system (MFP Exhibits 107,108,110), problems with the containment recirculation sump (MFP Exhibit 113), control of tools (MFP Exhibit 108) and unprotected disconnected instrument lines (MFP Exhibit 106).

**511- Finding: PG&E has a long history of problems involving control of foreign material.**

512- Problems involving the control of foreign material is a long standing issue at DCNPP. This is evidenced by its history of violations and discrepancies.

513- On 5/5/88, the NRC issued a Severity Level V violation for deficiencies in the control of tools on 4/14/88. NRC NOV in IR 88-07 (5/5/88), MFP Exhibit 108, NOV.

514- Soon after the issuance of this violation on 5/5/88, PG&E was again cited on 6/17/88 for lack of required cleanliness controls on 3/21 and 4/6/88. "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 was a Severity Level IV violation. NRC IR 88-10 and 88-11 (6/17/88), MFP Exhibit 107, NOV.

515- Early in 1990, the NRC issued Enforcement Action 89-241 which cited three Severity Level III violations for problems relating to the containment recirculation sumps, and imposed a civil penalty in the amount of $50,000. One of these violations (A) related to a condition first identified in 1985. PG&E reply to NRC EA 89-241 (3/12/90), MFP Exhibit 113, enclosure at 1.

516- During the period from 10/12/91 through 10/21/91, several cases of loose debris in containment of Unit 2 were identified and found to be due to "lack of a comprehensive program for control of loose debris and materials when containment integrity is established during high intensity work periods." NCR DC2-91-TN-N102 R2 (11/18/92), MFP Exhibit 109 at 1. During 1R5 (11/92), an NRC inspector again found loose debris (paper, plastic bag, wipealls, tool bag, water jug and tool bin) unattended in containment. Id.

517- There have been a number of violations of foreign material exclusion area (FMEA) boundaries, both non-outage and outage related. NCR DCO-91-MM-N042 (5/19/92, MFP Exhibit 110) was initiated because of a violation at the Unit 1 reactor vessel head during 1R4 that could have resulted in foreign material entering the reactor coolant system (RCS). The NCR addressed discrepancies identified for both units during 2R3 and 1R4. MFP Exhibit 110 at 1,2.

518- In the Diablo Canyon Shutdown Risk and Outage Management Inspection for Unit 1 on 12/8/92, a deficiency was noted involving the control of foreign materials. It stated: "No procedure existed for ensuring foreign material exclusion on disconnected instrument lines." NRC Diablo Canyon Shutdown Risk and Outage Management Inspection (NRC IR 50-275/92-201) (12/8/92), MFP Exhibit 106 at ii.

519- Other similar events not previously noted have been documented in MFP Exhibit 110 at 14,15: NCR DC1-86-TN-N143 addressed a problem with a tool zone not being maintained around the spent fuel pool; NCR DC1-88-TN-N051 addressed generic housekeeping; NCR DC1-91-TN-N017 addressed the discovery of a dowel pin in fuel bundle E37 during 1R4.

520- The Licensing Board concludes that PG&E has a long history of violations and deficiencies involving control of foreign material. Furthermore, this history indicates that the problems are not yet resolved and that the maintenance and surveillance program is deficient.

**521- Finding: PG&E's program to control foreign material is not sufficiently comprehensive or effective. Additionally, the maintenance and surveillance organization has been slow to respond adequately to the variety of situations in which control of foreign material is at issue.**

Loose Debris in Containment

522- Loose debris in containment is of concern because if too much loose debris collects on the screens of the recirculation sump, the flow through the screens will be inadequate to supply the RHR pumps. MFP Exhibit 109 at 8. During the period from 10/12/91 through 10/21/91, several cases of loose debris in the Unit 2 containment were identified. Verification is required to insure that debris is removed from containment after each entry. Four people were identified as not having filled out M-45B data sheet certifying that they performed a visual inspection for loose debris when containment integrity had been established. Id. at 1. "A search of all containment entries against STP-M45B was reviewed. From 10/15/91 to 10/21/91, there were 1,041 entries concerning 346 individuals. Forty potential M-45B violations were identified as possible... Half dozen examples of people in containment who did not complete an STP M-45B were noted." Id. at 20.

523- During 1R5 (11/92), an NRC inspector found loose debris (paper plastic bag, wipealls, tool bag, water jug and tool bin) unattended in containment. He "found an area near the sump which had materials left unattended. Also, material was left unattended in the fan coolers area and the Radiation Protection (RP) off pad... Two incidents on the 91 foot elevation were noted. One of which involved a rag tied around a balancing pipe." Id. at 27.

524- PG&E determined that the root cause of these events was the lack of a comprehensive program for control of loose debris and materials when containment integrity is established during high intensity work periods. PG&E found that a contributory cause was the lack of understanding of the housekeeping and work controls requirements by some individuals. Id. at 7.

525- The NRC reported that its "inspector's observations indicated that the licensee's program to control material inside containment was not comprehensive, and that the corrective actions indicated in the LER were not sufficient to prevent recurrence." MFP Exhibit 105 at 7.

Foreign Material in the Reactor Coolant System

526- PG&E has committed a number of transgressions of foreign material exclusion area (FMEA) boundaries, both non-outage and outage related. NCR DCO-91-MM-N042 was initiated because of a violation at the Unit 1 reactor vessel head during 1R4 that could have resulted in foreign material entering the reactor coolant system (RCS). The NCR addressed discrepancies identified for both units during 2R3 and 1R4. MFP Exhibit 110 at 1,2.

527- During installation of the CETNAS (Conoseals) on the Unit 1 reactor head in March of 1991, PG&E discovered that the FMEA covers over the instrument ports #74 and #75 were removed for 12 hours. This raised the potential for a loose part to enter the reactor coolant system and threaten the safe operation of the system. Id. at 2.

528- PG&E found the root cause of this FMEA violation was management failure to implement the FMEA program as described in applicable administrative procedures. Contributory causes were also noted:

1. There is a lack of ownership on specific jobs for FMEA, especially when multiple disciplines work the job. There is also an overall lack of ownership for the program.

2. There is inconsistent interpretation and implementation of FMEA requirements.

3. The FMEA procedure (C-10S4) is not "user friendly."

4. There is insufficient management emphasis on implementation of the FMEA program. Management expectations are not effectively communicated.

5. There is insufficient FMEA boundary identification.

MFP Exhibit 110 at 3,4.

529- MFP Exhibit 108 describes an earlier similar event. During the observation of the connoseal removal work on 3/21/88, the NRC inspector noted that the opening to the reactor vessel created by the work was left open at the completion of work. The "inspector was concerned for the cleanliness of the reactor since at a different reactor site a 1/8 inch piece of foreign material had caused a stuck control rod." MFP Exhibit 108 at 15. The inspector communicated this concern to the mechanics and the QC inspector. The openings to the reactor vessel were not covered until late in the day on 3/23/88, two days later. The NRC report concluded that the event demonstrated "untimely actions on the part of the plant staff in dealing with cleanliness problems. The problem was to the point that specific management expectations were not implemented." Id., cover letter.

530- PG&E received a Severity Level IV violation for the incident described above in March of 1988 and for another event which occurred in April of 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." MFP Exhibit 107, NOV.

531- On 4/6/88, work was initiated on the spare control rod drive mechanism. On 4/9, work was stopped due to ineffective barriers around the refueling cavity. A memo was issued by engineering regarding cleanliness controls. "Subsequent events showed that this memorandum was ineffective in precluding further occurrences." Id. at 20.

532- On 4/12, QC inspectors identified that cutting fluid and chips were being allowed to enter crevice areas on the reactor vessel head. Work was again stopped and procedures revised. But "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." Id. at 20,21.

533- On 4/22, while attempting to reinstall the upper internals, work was again stopped by the refueling crew due to the sighting of debris on the upper internals. The debris was retrieved: a broken tie wrap and paint chips. It was discovered that the removed head was stored immediately adjacent to the refueling cavity and a portion of the cable tray area hangs over the pool. Additionally, a great deal of dirt (up to 1/4" thick) and broken microphone ceramics were found on the upper area of the head. The engineer explained that this material would fall straight down and not into the refueling cavity. However, he further noted that one of the steel plates had been inadvertently kicked, fell, bounced off a structure and ended up in the refueling cavity pool, yet to be retrieved. Therefore, "the logic that dirt and debris would only fall straight down appeared to be faulted." Id. at 22.

> The licensee's actions up to the point of the inspectors involvement were ineffective in that they did not identify additional debris on the reactor vessel head which could be easily dislodged and find its way into the refueling cavity and possible reactor vessel. This is a significant condition, because debris in the refueling cavity or reactor vessel could impact reactor operations and fuel conditions. This was true despite memorandums of instruction by the engineering manager and increased QC surveillance. The failure to take timely effective corrective action to preclude recurrences of cleanliness deficiencies is an apparent violation of 10 CFR 50 Appendix B criterion XVI. Id.

534- It is readily apparent to the Licensing Board that PG&E has been unsuccessful at controlling debris in a variety of situations and time frames. The repetitive and continuing nature of these events and violations, despite purported corrective actions, demonstrate to the Board that the maintenance and surveillance program at DCNPP is inadequate to sufficiently resolve this issue.

Containment recirculation sumps

535- Early in 1990, the NRC issued Enforcement Action 89-241 which cited three Severity Level III violations for problems relating to the containment recirculation sumps, and imposed a civil penalty in the amount of $50,000. The violations included:

A. During 1R3 (10/6/89), a 1" vertical gap was identified in the upper grating assembly between the screen sections. Other gaps were found around a concrete column pedestal in the inclined section of the upper grating assembly. PG&E acknowledged that these gaps were identified in 1985 (8/2) and again in 1989 (11/26) and that "corrective actions taken in 1985 were inadequate to identify and correct the nonconforming conditions." MFP Exhibit 113, enclosure at 1,2.

B. Two emergency core cooling system subsystems were inoperable for a period of about 10 to 12 hours each while Unit 2 was in Mode 1 operation on 10/12/87 and 8/23/88 and while Unit 1 was in Mode 1 operation on 9/7/88, and 5/11/89. On those dates, the containment recirculation sump was inoperable because the screened access hatch was opened to allow the addition and pumpdown of borated water with hoses for calibration of the sump level detectors. With the sump access hatch open, the screen structure was not fully capable of performing its rated support function. During the stated periods, no action was initiated to reduce the reactor power to enter a lower mode of operation. Id. at 8,9.

C. On 5/11/89, PG&E performed an inadequate inspection of the Unit 1 containment sump for loose debris which could be transported within the containment sump and cause restrictions of the sump suctions during a LOCA condition. Even though containment integrity had been established, there was debris in the sump from at least the time of the last licensee inspection of 5/11/89 until 10/17/89 when debris was discovered and removed. PG&E notes that the

> primary reason for debris in the sump was failure to follow STP M-45... for containment inspections following maintenance activities. Also, the procedure was not explicit in defining inspection activities. In addition, plant management did not ensure that foreign material exclusion principles controlled recirculation sump activities. Id. at 11.

Control of Tools

536- On 5/5/88, the NRC issued a Severity Level V violation for an event which occurred on 4/14/88. In a Zone 3 housekeeping area, established for the Unit 1 reactor vessel head cable tray area, loose tools were found (a pocket knife, cutting blade, an open allen wrench set) which were not entered on the provided log. MFP Exhibit 108, NOV. PG&E

acknowledges that the violation occurred due to insufficient attention to cleanliness control requirements by supervision and craftsmen. PG&E reply to NOV in NRC IR 88-07 (6/6/88), PG&E Exhibit 25, enclosure at 1.

Disconnected Instrument Lines

537- In the Diablo Canyon Shutdown Risk and Outage Management Inspection for Unit 1 on 12/8/92, a deficiency was noted involving the control of foreign materials. It stated: "No procedure existed for ensuring foreign material exclusion on disconnected instrument lines." MFP Exhibit 106 at ii.

**538- Finding: The issue of control of foreign material has safety significance.**

539- PG&E asserts that the incidents cited above hold "very low safety significance, in some cases, none." Tr. at 1523. We disagree. While some instances of loose debris and foreign materials are not safety significant in and of themselves, they reflect a programmatic deficiency which may affect those areas where loose debris is a safety problem. For instance, with respect to the problems involving debris left in containment; it has been established that if too much loose debris collects on the screens of the recirculation sump, the flow through the screens will be inadequate to supply the RHR pumps. See MFP Exhibit 109 at 8.

540- Debris in the reactor cooler system could also potentially create some serious problems.

> The presence of a loose part in the primary coolant system can be indicative of degraded reactor safety

resulting from failure or weakening of a safety-related component. A loose part, whether it is from a failed or weakened component or from an item inadvertently left in the primary system during refueling or maintenance activities can contribute to component damage and material wear by frequent impacting with other parts in the system. A loose part can pose a serious threat of partial flow blockage with attendant departure from nucleate boiling (DNB) which in turn could result in failure of fuel cladding. In addition, a loose part increases the potential for control-rod jamming and for accumulation of increased levels of radioactive crud in the primary system. MFP Exhibit 110 at 4.

It has been noted that at a different plant, a 1/8 inch piece of foreign material had caused a stuck control rod. MFP Exhibit 108 at 15. Loose debris in the containment sump could be transported within the containment sump and cause restrictions of the sump suctions during a LOCA condition. MFP Exhibit 113 at 11. Hence, the potential for serious consequence from "loose debris" is real. The Licensing Board finds PG&E's maintenance and surveillance program lacking due to its failure to sufficiently control foreign material.

**541- Finding: The problem of control of foreign material is pervasive at DCNPP. It is not limited to the incidents cited above.**

542- PG&E has a variety of terms for describing the issue. It uses "control of foreign material," "cleanliness" and "housekeeping." These all describe the problem of keeping unwanted "debris" from damaging equipment or interfering with the operation of equipment. The Licensing Board finds that this problem is not limited to the incidents cited above. The Board notes that many other events that have occurred at the plant involve this "housekeeping" issue. See also Specific Findings on Corrosion, Main Feedwater Pump Overspeed Trip, Auxiliary Salt Water Pump Vault Drain Check Valves, and Limitorque 2-FCV-37 Failed to Close.

543- Additionally, PG&E's own 1993 Self-Evaluation Report has identified housekeeping as an area that requires attention. "Deficient housekeeping practices and ineffective implementation of the housekeeping program have resulted in numerous observed conditions of degraded materiel condition and housekeeping discrepancies." This self-evaluation team identified 159 housekeeping and 210 material condition discrepancies. It further noted that programs for management of plant housekeeping have not been effective in maintaining plant cleanliness. A quality control surveillance report for May concluded that "plant material conditions remain low and minor housekeeping discrepancies remain high." PG&E Self-Evaluation of DCNPP (7/93), MFP Exhibit 35.

544- It is clear that a clean and well maintained facility is required for the safe operation of DCNPP. There have been repeated instances of foreign debris contamination at DCNPP, and PG&E has failed to effectively resolve this problem - despite numerous opportunities to do so. The Board finds PG&E's control of foreign material inadequate and unacceptable.

STEAM GENERATOR FEEDWATER NOZZLE CRACKING

MFP Exhibit 117: LER 1-92-022-00 (10/30/92)

Transcript pages: 1535-1557
PG&E Testimony: 91-93

545- During 1R5 (9/24/92), ultrasonic testing (UT) of the Unit 1 steam generator (SG) feedwater nozzles and piping identified circumferential linear indications on piping in the main feedwater system near SG 1-1, SG 1-2, SG 1-3 and SG 1-4 nozzle-to-pipe welds. LER 1-92-022-00 (October 30, 1992), MFP Exhibit 117 at 3. These cracks were thought to be beyond the ASME Code flaw acceptance criteria and portions of the piping were replaced. Id. at 3,4. Metallurgical analysis later revealed that the identified flaws were acceptable. Id. at 1,2.

546- Additionally, erosion/corrosion was found on all four Unit 1 SG thermal sleeves. Id. at 3. PG&E promised to install new, redesigned thermal sleeves during the next outage. Tr. at 1555.

547- PG&E claims that its discovery and repair of the SG nozzles "is an excellent example of the proper functioning of the DCPP maintenance and surveillance program, especially in assimilating industry experience and proactively initiating repairs even where existing standards do not require such repairs." PG&E Ts. at 93.

548- PG&E testified that it inspected and repaired the SG nozzles after one of its engineers visited TVA's Sequoyah nuclear power plant and observed a problem there with feedwater nozzle cracking. Since DCNPP has similar nozzle welds on each Unit 1 and Unit 2 SG, he recommended inspections at DCNPP be made at the next scheduled refueling outage. MFP Exhibit 117 at 3 and PG&E Ts. at 92.

**549- Finding: PG&E was initially notified of the possibility of cracking in the feedwater system piping in an NRC bulletin in 1979. Its response to this bulletin was inadequate and incomplete.**

550- The Board disagrees with PG&E's analysis. PG&E's response to SG nozzle cracking has been neither adequate nor proactive. In fact, thirteen years earlier, the NRC had warned PG&E and other licensees of the potential for cracking in the steam generator feedwater nozzle welds in NRC Office of Inspection and Enforcement (IE) Bulletin 79-13, Revision 2, "Cracking in Feedwater System Piping" (10/16/79). IE Bulletin 79-13 identified feedwater nozzle-to-pipe welds in 14 Westinghouse and Combustion Engineering power plants and made recommendations for examinations of piping. MFP Exhibit 117 at 2.

551- PG&E responded to the IE bulletin with examinations and inspections during 1R1 and 1R2, and determined at that time that the piping and welds were "acceptable under ASME Code acceptance criteria." Id. But during its subsequent investigations of feedwater nozzle cracking in September of 1992, PG&E discovered that the Unit 1 SG feedwater nozzle radiography during 1R1 was incomplete or not in full compliance with Bulletin 79-13.

> The pipe-to-pipe welds adjacent to the SG nozzle-to-pipe welds were radiographed instead of the SG nozzle-to-pipe welds. Also, recent reviews suggest that the radiography techniques used for the Unit 1 post hot function testing (9/79), 1R1 (10/86), and 1R2 (5/87) SG nozzle examinations may not have been in full compliance with Bulletin 79-13 requirements, such as penetrameter thickness, sensitivity, and density values. Id. at 3.

552- PG&E believes that even if these radiographs had been conducted properly, they still would not have detected the small thermal fatigue cracking experienced on these segments; and thus, PG&E concluded that its previous errors had "no safety significance." Id. The Board finds, however, that PG&E's previous errors did have safety significance, because they were so blatant, because they remained uncorrected for so long, and because they could have led to a serious safety risk had the rate of cracking been more rapid. Clearly, the 1979 IE bulletin was concerned with nozzle cracking; yet for unexplained reasons, PG&E did not examine the SG nozzles during 1R1. Moreover, it took over six years before PG&E discovered this obvious error - a lengthy period of time in which the cracking could have been significantly more severe. Thus, we find that, contrary to PG&E's view, this incident exemplifies a maintenance and surveillance program that is not functioning as it should. See General Findings regarding Untimely Detection and Correction of Aging Effects.

553- Moreover the Board finds it erroneous and misleading for PG&E to boast that repairs were made "even where existing standards do not require such repairs." In fact, the SG repairs were done because PG&E believed, based on its own engineering evaluation, that the flaws were beyond ASME Code acceptance criteria and **must** be replaced. Only later did PG&E discover that the flaws were acceptable.

PROCEDURAL CONTROLS DURING SHOT PEENING OPERATIONS

MFP Exhibit 118: NRC NOV in NRC IR 92-26 (11/13/92)
PG&E Exhibit 22: PG&E Reply to NOV in NRC IR 92-26 (12/14/92)

Transcript pages: 1557-1565, 2204-2208

554- Several instances occurred which involved the unanticipated spread of contamination and/or airborne radioactivity which resulted from inspection and maintenance operations in the Steam Generator (SG) hot and cold legs. Simultaneous eddy current (cold leg) and shot peening (hot leg) activities were performed on all four SGs at once. NRC NOV in NRC IR 92-26 (11/13/92), MFP Exhibit 118 at 8.

555- PG&E determined that the root cause of these events was the lack of establishing clear responsibility for proper operation of the HEPA ventilation system. In addition, the following contributing causes were given:

1. eddy current personnel had not been properly trained;
2. the procedures did not address step-by-step operation of the HEPA ventilation system;

3. positive control of the dry air supply valve had not been sufficiently established;

4. no low flow alarms or indicators had been made available to the shot peening and eddy current operators to indicate improper SG bowl ventilation.

Id. at 10.

556- There were three incidents that led to the spread of radioactivity:

Incident 1: On 9/25/92, the cold leg manway door on SG 1-1 was opened while the SG was pressurized by a Copus blower. This resulted in the spread of contamination (and hot particles) outside the posted hot particle zone. Id. at 9.

Incident 2: On 9/26/92, the cold leg manway door on SG 1-3 was opened for eddy current maintenance. The dry air supply valve to the hot leg was either not fully closed or later bumped open. In addition, shot peening continued with the cold leg manway door open. This resulted in air flow out of the cold leg and caused a high airborne condition in containment. Several workers received uptakes from this incident. The highest uptake was approximately 15 MPC hours. Id.

Incident 3: On 10/2/92, the cold leg manway door on SG 1-4 was opened for about one hour while shot peening continued. This resulted in air flow out of the cold leg and airborne alarms in the SG work area. Id.

557- NRC issued a Severity Level IV violation for the incident that occurred on 10/2/92:

...eddy current and shot peening operators failed to implement the provisions for control of radioactivity as given in MRS-2.4.2-GEN 35, Section 9.7.13.5.2, in that ventilation was interrupted to the steam generator cold leg for one hour, and shot peening continued without switching of the ventilation and dry air supply as required. This failure to implement the procedure resulted in the unanticipated spread of airborne radioactivity. Id., NOV at 1.

558- **Finding: Maintenance personnel were responsible for the recurrent generation of unanticipated airborne radioactivity during maintenance activities performed on the Unit 1 steam generator. The spread of radioactivity was a direct result of their activities.**

559- PG&E discounts the importance of this incident by claiming that it was a health physics problem - therefore unrelated to maintenance; the three incidents involving the spread of radioactivity had no bearing on the maintenance and surveillance of equipment. Tr. at 1563. The violation was issued for inadequate corrective action for the airborne radioactivity. And that activity was a health physics activity. Tr. at 2207. PG&E additionally draws attention to the NRC's comment that its "overall control of radiological hazards encountered during steam generator work in the Unit 1 outage appears exemplary..." Tr. at 1559.

560- However, no party is presently challenging PG&E's overall control of radiological hazards. The Licensing Board asserts that the issue at hand involves the question as to whether or not PG&E's maintenance and surveillance organization adequately performed a maintenance and surveillance activity. PG&E acknowledges that the performance of shot peening was a maintenance activity. Tr. at 1564. The NRC concurs. Tr. at 2206. There is, additionally, no argument that the three incidents of radiological contamination occurred due to inadequacies on the part of the personnel performing the shot peening and eddy current testing. Tr. at 1561. Thus, the Board determines that PG&E's maintenance and surveillance organization was responsible for the spread of airborne radioactivity on three occasions during work on the Unit 1 steam generator.

**561- Finding: Corrective actions taken after the first and second incidents of unanticipated spread of radioactivity were ineffective in preventing the third incident.**

562- As a result of Incident 1, PG&E prepared written instructions emphasizing the need for negative SG pressure to be maintained relative to the Containment atmosphere. These instructions were reviewed with the personnel involved and posted at the work stations. PG&E's Quality Evaluation later concluded that "the instruction would have been sufficient to prevent Incidents 2 and 3 had it been understood and followed." MFP Exhibit 118 at 9.

563- After Incident 2, all SG work was stopped and the Containment was evacuated. After holding a critique, PG&E added a checklist to the eddy current procedure to control breaches of the cold leg manway. In addition, an instruction was added to the shot peening procedure to control continuation of shot peening if the cold leg manway door remained open for more that 15 minutes. Quality Evaluation later concluded that the corrective actions from Incident 2 would have been sufficient to prevent Incident 3 had they been understood and followed. Id. at 9,10. The NRC noted that the corrective actions taken for Incidents 1 and 2 "were not effective, as evidenced by the failure to follow the newly established shot peening controls in Incident 3." Id. at 11.

**564- Finding: One of these incidents is an example of poor communication and coordination between maintenance and eddy current testing personnel.**

565- PG&E testified that during the incident involving simultaneous shot peening and eddy current testing, the two groups performing this work on the steam generator were having an "interface problem." They "weren't talking to each other." Tr. at 1562. In addition, as noted in PG&E's root cause analysis, responsibility for the proper operation of the HEPA ventilation system was unclear. MFP Exhibit 118 at 10. The Board finds that this is another example of problems caused by poor communication. In some cases, it has been poor communication between maintenance and other groups; in others there has been poor communication between surveillance groups. In this case, we presume that maintenance personnel were responsible for both the eddy current and the shot peening activities, but were not communicating with each other. We find that a pattern of poor communication exists in the maintenance program, which affects the safe operation of the plant and therefore prevents us from finding that it is adequate.

566- In conclusion, the Licensing Board finds that a number of poor maintenance practices, including poor communication, unclear lines of responsibility, inadequate training, inadequate procedures, failure to establish positive control of the dry air supply, and lack of proper alarms, contributed to these events. Moreover, corrective actions taken by PG&E's maintenance and surveillance organization after the first two events were inadequate to prevent recurrence of a significant incident involving the spread of airborne radioactivity. The Board finds that these factors, taken together with the other deficiencies described in this decision, indicate an inadequate maintenance and surveillance program at DCNPP. See also Lack of Communication and/or Coordination and Previous Corrective Action Failed to Prevent Recurrence in the General Findings.

UNPLANNED ESF ACTUATIONS DUE TO PERSONNEL ERROR

MFP Exhibit 119: NCR DC1-92-TI-N039 (10/2/92)
MFP Exhibit 120: LER 1-92-013-00 (10/2/92)
MFP Exhibit 121: NCR DC1-91-OP-N038 (5/3/91)
MFP Exhibit 122: LER 1-91-011-00 (8/1/91)
MFP Exhibit 122A:NCR DC1-91-OP-N059 (7/23/91)
MFP Exhibit 123: LER 1-91-009-00 (6/17/91)
MFP Exhibit 124: NCR DC1-91-TT-N047 D4 (1/24/92)
MFP Exhibit 126: NCR DC2-91-TI-N088 D2 (10/30/91)
MFP Exhibit 127: LER 2-91-007-00 (11/1/91)

Transcript pages: 1566-1588

567- Numerous Engineered Safety Features (ESF) actuations have occurred at DCNPP. One such event occurred during preparation of Unit 1 for entry into Mode 4 on 3/23/91. Operators were performing Solid State Protection System (SSPS) Slave Relay Tests. A non-licensed operator inadvertently actuated SSPS Train A test switch S-816 which caused the SSPS slave relay K603A to actuate. Actuation of this slave relay initiated an unplanned start of diesel generator 1-1 and a realignment of safety injection valves (an ESF). PG&E determined the root cause to be personnel error due to failure to follow procedures, inattention to detail and failure to perform the requirements of the verification process. NCR DC1-91-OP-N038 (5/3/91), MFP Exhibit 121.

568- A Unit 1 reactor trip occurred on 5/17/91 as a result of personnel error. Two I&C technicians were performing a surveillance test procedure on nuclear instrumentation power range channel N41. One technician inadvertently pulled the fuse for NI channel N42 instead of for N41. This resulted in a reactor trip. Following the reactor and main turbine trips, two condenser steam dump valves (SDV) malfunctioned. Reactor Coolant System (RCS) pressure and temperature decreased sufficiently to result in a safety injection (SI). An unusual event was subsequently declared. During the event, RCS cooldown exceeded the allowable rate of 100 degrees Fahrenheit per hour. PG&E attributed the reactor trip to personnel error in that the I&C technicians did not perform self-verification. LER 1-91-009-00 (6/17/91), MFP Exhibit 123 and NCR DC1-91-TT-N047 D4 (1/24/92), MFP Exhibit 124.

569- On 7/5/91, an unplanned start of ESF equipment occurred when an operator inadvertently actuated the wrong SSPS test switch. SSPS Train B test switch S822 was actuated instead of the intended SSPS Train A test switch S822. PG&E determined the root cause of this event to be, again, personnel error, inattention to detail and failure to follow the steps requiring verification. LER 1-91-011-00 (8/1/91), MFP Exhibit 122 and NCR DC1-91-OP-N059 (7/23/91), MFP Exhibit 122A.

570- Another inadvertent SI occurred on 10/6/91 because two I&C technicians failed to utilize the applicable procedure during performance of an STP and did not practice self-verification or concurrent verification. Two I&C technicians were reconfiguring the SSPS per STP I-16D4. Both technicians incorrectly placed the outputs in operate prior to inhibiting the inputs resulting in an inadvertent SI. NCR DC2-91-TI-N088

D2 (10/30/91), MFP Exhibit 126 and LER 2-91-007-00 (11/1/91), MFP Exhibit 127.

571- On 9/6/92, the Fuel Handling Building Ventilation System (FHBVS) shifted to iodine removal mode (an ESF actuation). This shift was caused by a high radiation alarm on radiation monitor RM-59. PG&E found the root cause of the RM-59 alarm to be personnel error; the I&C technician was testing RM-58 and, after a pause to document test results, he inadvertently actuated the wrong channel. He failed to perform an adequate self-verification as required by I&C department policy. NCR DC1-92-TI-N039 (10/2/92), MFP Exhibit 119 and LER 1-92-013-00 (10/2/92), MFP Exhibit 120.

572- **Finding: Numerous inadvertent ESF actuations have occurred at DCNPP due to personnel errors, specifically failure to perform adequate self-verification.** "This has been a generic problem at DCPP and in the rest of the industry." MFP Exhibit 124 at 15.

573- PG&E determined that the root cause of the ESF which occurred on 3/23/91 was due to

> personnel error in that the Operators involved failed to perform the task in accordance with established procedures and policies because of inattention. Neither the Concurrent Verification process nor the Self Verification process were properly implemented during the performance of this STP. MFP Exhibit 121 at 6.

574- For the SI that occurred on 5/17/91, the root cause was determined to be "personnel error (cognitive) in that the I&C technician did not perform self-verification. I&C policy... dated June 30, 1988, requires that an individual verify his own action as correct prior to performing the action." MFP Exhibit 123 at 5.

575- An ESF actuation occurred on 7/5/91. "The root cause of this event was personnel error (inattention to detail). The operator performing the test had the test procedure in hand, but failed to pay adequate attention to the test content or to the steps requiring alarm verification." MFP Exhibit 122 at 5.

576- Another SI occurred on 10/6/91. The root cause of the event was determined to be due to "personnel error, in that technicians did not utilize the applicable procedure during the performance of STP I-16D4." MFP Exhibit 126 at 7.

577- The root cause of the RM-59 high radiation alarm which activated an ESF was "determined to be personnel error... The I&C technician... failed to recognize that he was operating the wrong channel, and also failed to perform an adequate self-verification as required by I&C department policy... The technician had been trained and was aware of the requirement to perform self-verification." MFP Exhibit 120 at 3.

578- Previous inadvertent ESF actuations have been reported that were caused by improper self-verification and concurrent verification techniques: LER 1-84-008 (MFP Exhibit 126 at 9); LER 1-88-020 (MFP Exhibit 122A at 7); LER 1-88-023 (MFP Exhibit 122A at 7); LER 1-88-030 (MFP Exhibit 122A at 7);

LER 1-89-012 (MFP Exhibit 122A at 7); LER 1-90-004 (MFP Exhibit 122 at 6); and LER 1-91-005 (MFP Exhibit 122A at 7).

579- Clearly, numerous inadvertent ESF actuations have occurred at DCNPP as a result of inattentive personnel. The operators and technicians that fail to practice self-verification in their work have put undue stress on the equipment. The Licensing Board finds this to be an unacceptable situation; the repetition of these personnel errors indicates that PG&E's corrective actions have not been successful.

**580- Finding: Inadvertent ESF actuations are significant occurrences.**

581- Whether the unplanned ESF actuations are initiated by operators or maintenance personnel is irrelevant. What is significant is that these ESF actuations unintentionally exercise emergency equipment, and the upkeep of this equipment is the responsibility of the maintenance and surveillance organization.

582- Unplanned ESF actuations are reportable to the NRC. Tr. at 1568. And the degree of significance of each inadvertent ESF actuation depends upon the particular ESF system that is actuated. PG&E has admitted that "a safety injection is something you would never want to inadvertently have actuate." Tr. at 1576. "Definitely, we try to avoid tripping the plant." Tr. at 1578. Yet, two of the inadvertent ESF actuations summarized above resulted in safety injection. Both of these events, incidently, occurred due to errors made by I&C personnel. MFP Exhibits 123,124,126,127.

583- During the unplanned SI that occurred on 5/17/91, two condenser steam dump valves (SDV) failed to close. Reactor coolant system (RCS) pressure and temperature decreased sufficiently to result in a SI. MFP Exhibit 123 at 2. The RCS cooldown exceeded the allowable rate of 100 degrees Fahrenheit per hour, and an unusual event was declared. Id. at 3.

584- The failure of the SDVs was obviously not a surprise, for it was noted that "due to previous experience with SDVs failing to close following actuation, operators quickly identified the malfunction." Id. at 2. PG&E determined the cause of the reactor trip to be personnel error in that the I&C technicians did not perform self-verification. The cause of the SI was steam dump valves that failed open and overcooled the RCS. Id. at 1.

585- The potential for equipment damage during this event due to overcooling was present, but PG&E was lucky: "The Westinghouse evaluation concluded that the... Unit 1 transient did not adversely affect the structural integrity of the affected components and system." Id. at 5.

586- A subsequent inadvertent SI actuation occurred on 10/6/91. Equipment problems were not involved in this event, yet another unexpected result did occur; there was a personnel safety near-miss. He was working on an MSIV when the inadvertent SI occurred, and he had to jump back to avoid the closing valve. He experienced some minor injuries. MFP Exhibit 126 at 11.

587- The Licensing Board finds that unplanned ESF actuations are not generally "benign" as PG&E would like to have us believe. Tr. at 1567. Rather, the incidents provided by SLOMFP clearly demonstrate that unexpected and adverse results can result from seemingly benign mistakes. The Board concludes that the number of personnel errors involving unplanned ESF actuations reflects poorly upon the adequacy of the maintenance and surveillance program at DCNPP. See General Findings for a discussion regarding Personnel Errors.

LIMITORQUE VALVE FAILURE

MFP Exhibit 128: NCR DC2-92-EM-N026 D8 (9/17/92)
MFP Exhibit 129: LER 1-92-010-00 (10/15/92)

Transcript pages: 1589-1592

588- PG&E has noted the "critical safety importance of Limitorque operators." NCR DC2-92-EM-N026 D8 (9/17/92), MFP Exhibit 128 at 8. The safety function affected by the potentially degraded motor operated valves (MOVs) is the ability of a particular valve to open or be repositioned if necessary to support a safe plant shutdown. LER 1-92-010-00 (10/15/92), MFP Exhibit 129 at 4.

589- During outage 2R4, PG&E replaced the spring packs on a number of MOV actuators, including SI-28805B and SI-2-8923A.

Id. at 2. This was part of a program responding to a valve actuator spring pack relaxation problem previously experienced at DCNPP. All eleven spring packs that were preassembled for use in 2R4 were assembled by the same individual. Id.

590- On 6/2/92, while performing current signature testing on Limitorque MOV SI-2-8923A, it would not fully open on the second and subsequent attempts to stroke the valve. A similar failure was identified that had occurred previously during post-maintenance testing after overhaul of MOV SI-2-8805B during 2R4. Id.

591- Investigation revealed that the worm cartridge bearing lock nut setscrew had not been adequately tightened when the spring packs were installed during 2R4. This resulted in the lock nut unscrewing itself from the worm shaft, allowing the worm shaft to pull away from the spring pack. This caused the torque switch to be pulled in the open direction. With the torque switch open, the valve strokes until the torque bypass switch opens at about 35% of valve stem travel. Id.

**592- Finding: Maintenance procedures were inadequate; they did not include adequate instructions for tightening the setscrew or the worm shaft locknut. Moreover, maintenance did not communicate adequately with the vendor in order to learn of changes in the worm shaft material.**

593- PG&E found that the root cause of the MOV failure was personnel error during the assembly of the spring pack assembly. The individual did not adequately secure the worm shaft lock nut in place. MFP Exhibit 129 at 4. PG&E also identified two contributory causes: maintenance procedures did not include adequate instructions for tightening the setscrew at the worm shaft locknut, and the vendor had changed the hardness of the worm shaft "thereby limiting the effectiveness of the setscrew in deforming worm shaft threads for securing the locknut." Id. The TRG also noted the "lack of any technical guidance from the vendor or other sources on the installation technique for the worm gear shaft locknut setscrew." MFP Exhibit 128 at 13.

594. The Licensing Board questions PG&E's determination of the root cause of this incident as being merely personnel error. Given the inadequate guidance for installation, and given the material substitution by the manufacturer, the individual maintenance employee who assembled the spring packs was destined to err. In light of the critical safety importance of the MOVs, PG&E's maintenance and surveillance program should have been able to provide personnel with detailed instructions on the proper method for securing the locknut to the worm gear shaft. The Maintenance Department should also have - but apparently does not have - some procedure for verifying the material content of replacement parts. The Board finds PG&E's maintenance and surveillance program deficient in these respects. See discussion in

General Findings regarding Manufacturing/Vendor Deficiencies and Internal Defects.

MOTOR PINION KEYS IN LIMITORQUE MOTOR OPERATORS

MFP Exhibit 132: LER 1-91-021-00 (8/28/92)

Transcript pages: 1615-1625

595- On 9/16/91, during post-modification testing, a sheared motor pinion key was identified in the motor operator for cold leg isolation valve SI-2-8808B. PG&E filed an LER regarding the event. LER 1-91-021-00 (8/28/92), MFP Exhibit 132 at 2.

596- The sheared key was inadvertently discovered after an electrical maintenance technician failed to request that control room switch for valve SI-2-8809B be placed in neutral prior to manually operating the valve. The electrical engagement of the motor operator during manual operation (short stroking) resulted in application of a force higher than usual (but still within design limits). Further attempts to electrically stroke the valve failed. Id. at 3.

597- PG&E inspected the motor operator and found that the motor pinion key was sheared. The sheared key allowed the motor drive shaft to rotate within the pinion gear, thus preventing the valve from opening. Id.

598- Subsequent inspections identified similar failed keys in the motor operators for accumulator discharge isolation valves SI-2-8808B and SI-2-8808D. Id.

599- In 10/91 and in 3/92, PG&E received information from another nuclear power plant that had experienced similar Limitorque motor operator key shearing problems. In addition to sheared keys, that plant noted that motor shaft deformation and cracking may occur. In response to this information, PG&E performed an inspection and found "small cracks emanating from both corners of the keyway" on the SI-2-8809B motor shaft. Id.

600- PG&E found that the root cause of the sheared motor pinion key was that "the key material was inadequate." Id. at 4. According to PG&E, the key was supplied with the motor operator by the vendor. "The key material is considered outdated but still acceptable according to the vendor's design." PG&E also determined that the inadequate key material was also the root cause of the motor shaft keyway cracking. Id.

**601- Finding: The sheared key and the subsequent discovery of a vendor deficiency (the inadequate key material) was identified by maintenance personnel because of an incorrectly performed post-maintenance test.**

602- A contributory cause of the event was determined to be short stroking while the valve was being manually operated. "There was a miscommunication between the maintenance personnel performing the test and the operations personnel in the control room and as a result a much higher stress was put on this key than would normally be put on during normal operations." Tr. at 1617.

603- The Licensing Board observes that it was by way of this "miscommunication" that the inadequate key material was inadvertently discovered. Otherwise, it might not have been found until the valve failed during operation.

604- We also note that while in this case, the communication error between the maintenance and operations personnel had a result that was ultimately fortuitous, it nevertheless reflects a pattern of miscommunications between maintenance and operations, which has caused other problems in the plants. <u>See</u> General Findings regarding Lack of Communication and/or Coordination. Thus, we find this to be further evidence of a programmatic communications deficiency in the maintenance and surveillance program.

605- The Board is concerned regarding the significant number of internal defects in safety components that are found only through luck, or after a significant lapse of time in which PG&E has relied on the defective components, and then belatedly discovers the defects. PG&E's inability to detect and correct these hidden defects in a timely way could have a significant adverse effect on safety, especially in the defects were present in both trains of redundant safety systems. The Board finds that these "blind spots" represent a significant weakness in PG&E's maintenance program.

CONTROL OF LIFTING AND RIGGING DEVICES

MFP Exhibit 135: LER 1-91-004-02, Special Report 91-02 R1, Diesel Generator 1-1 failure to load within TS limits (7/29/92)
MFP Exhibit 136: NCR DC1-91-MM-N028 (10/23/91)
MFP Exhibit 137: NRC IR 92-16 (7/7/92)
PG&E Exhibit 27: PG&E Reply to NOV in NRC IR 92-16 (8/5/92)

Transcript pages: 1626-1646, 2247-2255

Loss of Offsite Power

606- On 3/7/91, Unit 1 was being refueled and a mobile crane was being used to lift a relief valve into position for installation onto a main steam line outside of containment. The boom of the mobile crane came too close to the 500 kV power lines. It arced to ground through the crane boom and caused a loss of offsite power to Unit 1. The 230 kV startup power system had been cleared for maintenance and was not available. LER 1-91-004-02, Special Report 91-02 R1, Diesel Generator 1-1 failure to load within TS limits (7/29/92), MFP Exhibit 135 at 2.

607- The emergency diesel generators started and loaded the vital busses. This constituted an ESF and momentary loss of residual heat removal. At the time of the event, refueling was in progress with five fuel assemblies remaining to be reloaded to complete the reload sequence. One assembly was located in the manipulator crane mast in the full up position.

The manipulator crane was positioned over the core. Another assembly was located in the upender inside containment in the horizontal position. The other three assemblies were in the spent fuel pool. NCR DC1-91-MM-N028 (10/23/91), MFP Exhibit 136 at 2.

608- PG&E found the root cause to be personnel error by the crane operator and the foreman in that they failed to implement PG&E's accident prevention rules. They did not follow the accident prevention rules and did not recognize the electrical safety issues during job planning and execution. MFP Exhibit 135 at 1,10.

609- Many systems were affected by the loss of offsite power. MFP Exhibit 136 at 5-9.

610- It took approximately 5 hours to restore offsite power from the 230 kV system. MFP Exhibit 135 at 11.

**611- Finding: The crane operator and the foreman failed to follow the accident prevention rules.**

612- The one rule that was violated that would have prevented this event is in section 4, rule 406 which begins "Electrical apparatus and lines shall always be considered as energized unless they are positively known to be de-energized." Other violations of Accident Prevention Rules include the failure to: (1) plan the work that may present unusual hazards; (2) instruct the workers on line or equipment condition; (3) work a safe distance from energized lines; (4) obtain a clearance;

(5) insure proper grounding of equipment; and (6) insure conditions are safe to perform work activities. MFP Exhibit 136, attachment 2.

613- PG&E testified that "5000,000 volts is a tremendous problem." Tr. at 1635. Thus, the Licensing Board finds it to be a serious safety concern that supposed trained and experienced PG&E employees allowed this event to occur. Furthermore, this event occurred despite the existence of multiple safety guidelines and in direct conflict with simple common sense.

**614- Finding: The existing management systems were not effectively utilized.**

615- PG&E's analysis of the event determined the root cause of the event to be "human error compounded by ineffective use of existing management systems." MFP Exhibit 136, Attachment 2. These are described in PG&E's NCR: **(1) The foreman was not adequately involved in the task.** He was involved in many other activities that had to be coordinated that day. Additionally, the tailboard that was conducted did not address the possibility of the 500 kV lines being energized. The foreman did not know that the Main Bank transformers had been energized on 3/6/91. Id. **(2) The support activities work practices did not require a clearance or appropriate controls for crane operation in the area of high voltage lines/transformers.** "It has been common practice for vehicle and foot traffic to occur in the vicinity of the high voltage lines/transformers. In addition, many materials (Sea trains, cable wire reels, etc.) are stored in this area. Position and movement of these items frequently is a direct violation of the APR and is an unsafe practice." Id. **(3) The evaluation of industry events and the resulting conclusions were ineffective in precluding this event.** The NRC and INPO previously supplied PG&E with notices of similar events that involved human errors while performing work activities around high voltage lines and transformers. NUREG 1410 addressed the loss of vital AC power and the RHR system during mid-loop operations at Vogtle Unit 1 on 3/20/90. INPO SER 17-88 noted electrocutions and injuries incurred while working near energized electrical equipment. INPO O&MR 272 discussed the inadvertent scram caused by contractors lowering an extension cord over the transmission lines to the startup transformer. Id. **(4) The written and verbal communication systems did not provide necessary job safety information to the foreman or crew.** The information regarding the re-energizing of the auxiliary transformer was not conveyed to the foreman or crew. Methods of communication include: (a) plan of the day; (b) outage status board; (c) PIMS bulletin board; (d) OCC hot item list; (e) tailboards. None of these methods were utilized during the job preparation to lift the relief valve. Id. **(5) Pressure for completion of the job and meeting schedules conflicted with management's expectations to perform the work safely.** Prior to outage start, a 58 day planned outage was communicated to plant staff and workers. After the outage started, a 45 day non-contingency schedule was the basis for schedule status. Constant reference as to how many days behind the non-contingency schedule were routinely posted. On the day of the accident, the outage status board included the message "11 days behind schedule overall." "Perceptions of this outage being 'not very successful' abound because of the constant reference to being behind schedule. Although not a direct cause of this event, these contribute to self imposed and peer imposed pressures to complete work quickly. Quick completion is not consistent with management expectations to do work safely and with quality. Management must remain perceptive to the indirect, and potentially conflicting, messages that can be sent." Id. **(6) Adequate emphasis was not placed on electrical safety for non-electrical workers during training courses.**

> The majority of personnel did not understand or relate the arcing distances of high voltages. It has been estimated over twenty plant personnel passed through the area of the crane on the morning of March 7, 1991 before the event. No one noticed the serious potential problem developing. A surprising number of personnel noted significant indicators, but failed to bring these to the attention of the crew moving RV-5... personnel heard the lines crackling, snapping, saw fans running, heard the transformers humming, and noted the transformer surface was warm... The logic of individuals noting these indicators was 'these people must know what they are doing or they world not be doing this work.' This thought process could have resulted in a multiple fatality accident. These fatalities would have included some of the individuals having noted the indicators... There were six people known to be within a 10' distance of the crane most of the time and five more at the pipe rack. All eleven would be in potential danger if the arc had occurred while RV-5 was at the pipe rack... This is

additional justification for increasing the awareness of plant personnel of the dangers of high voltage lines and transformers. Id.

616- **Finding: This incident involved the breakdown of multiple barriers that should have prevented it.**

617- PG&E's barriers that should have prevented this incident included the following: accident prevention rules when positioning the crane; electrical system training courses; management supervision (foreman); work activity clearances; NRC and INPO information notices and bulletins; and numerous communication systems to provide job safety information to the foreman and the crew. MFP Exhibit 136, Attachment 2.

618- The Licensing Board finds that each of these existing barriers were violated. As a result, PG&E jeopardized the health and safety of its employees and the general public. We find that these personnel errors, involving the breakdown of multiple barriers which should have prevented the accident, demonstrate the existence of a programmatic defect or fundamental flaw in PG&E's maintenance program. See also discussions in General Findings regarding Personnel Error, Breakdown of Multiple Barriers and Lack of Communication and/or Coordination.

619- **Finding: Many systems were affected by the loss of offsite power. Some of these systems did not function as designed or as expected.**

620- As documented in MFP Exhibit 136 at 5-9 and MFP Exhibit 135 at 5-8, multiple systems were affected during the event:

1. Diesel Generator (DG) 1-1 took approximately 19 seconds to start and load. This constitutes a valid failure; Technical Specification Limits requires that the DG load to its vital bus within 10 seconds of the event. The DG was unavailable for 321 hours and 11 minutes. The cause of the failure remains unknown. MFP Exhibit 135, cover letter at 1,2.

2. Residual Heat Removal (RHR) capacity was lost for less than one minute, and the Spent Fuel Pool Pumps were inoperable for approximately 23 minutes. (With the RHR and Spent Fuel Cooling Pumps inoperable, the water temperature in the refueling cavity increases.) One pump was manually restarted. During the time the pumps were not running, the calculated maximum temperature rise was approximately 1.8 degrees Fahrenheit. MFP Exhibit 135 at 10.

3. The Auxiliary Building Fans could not be restarted after the vital busses were re-energized by the DGs. The electrical power supply for the Auxiliary Building Ventilation control system failed after the event. The voltage regulator supplying power for the power supply and several capacitors had failed. MFP Exhibit 136 at 5.

4. Following the loss of Unit 1 AC power, the Unit 1 Control Room emergency lighting failed to function. It was discovered that the manual transfer switch to the emergency lighting dimmer panel was selected to the backup source and not to the emergency inverter. The backup source is supplied off of 480 volt bus 12D, which is not powered from the vital bus, and thus was not available during the loss of AC power. It was additionally found that the DC input breaker to the inverter was open. Id. at 6.

5. Emergency lighting did not function as expected in a number of areas in the Auxiliary Building and Containment. Id. at 7.

6. Plant public address system was not available in many areas of the plant, including Containment and the Fuel Handling Building. Id.

7. The intercom between Containment and the Control Room lost power. Id.

8. Unit 2 traveling screens wash failed when power was lost to Unit 1. PG&E noted it as a problem that Unit 1 supplies both screen wash systems. Id.

9. The Unit 2 turbine inlet high temperature alarm actuated coincident with the Unit 1 event and would not reset. Id.

10. The Unit 2 CEL-102 of the chlorine detection system lost power during the Unit 1 event. The detector was

being powered off of a Unit 1 normal power supply due to maintenance of its normal uninterruptable power source. Id.

11. The Auxiliary Building control panel and various radwaste equipment lost power. The equipment is powered off of Unit 1 non-vital power sources. During the period of time when non-vital busses were deenergized, the equipment was not available for service. Id. at 8.

12. The instrument air compressors powered from Unit 1 non-vital power did not function as expected. Both dryers for the instrument air system are powered off of Unit 1 non-vital power. "This lack of diversity has been previously recognized..." Id.

621- Thus, the single incident of a mobile crane coming into close contact with 500 kV power lines led to a chain reaction involving a loss of offsite power and a myriad of other problems. The Board views such a "domino effect" as indicating a fundamental problem with the level to which PG&E maintains its plant in an operable condition. If one mishap could lead to so many others, including safety failures, this plant is unacceptably vulnerable to breakdown and failure. Given the number of safety systems that failed as a result of this incident, the Licensing Board finds it simply an act of providence that greater consequences were not realized.

Incorrect Use of Chainfalls

622- On 5/28/92, 10-142 radwaste container was being prepared for shipping. The primary and secondary cask lids were being installed. This involved radioactive materials and was a complicated lifting task. A mechanical maintenance foreman supervised the rigging activity while the radioactive material was being placed in the cask and the rigging was attached to the cask lids. He then left the area. The cask lids were initially lifted by three slings and placed on the cask. The clearance between the cask and the cask primary lid was very tight and required some alignment. In an attempt to align the cask primary lid, the rigging crew decided to change the rigging to two chainfalls and a sling. They mistakenly chose one-ton chainfalls, rather than two-ton chainfalls, because they misjudged the weight. PG&E Reply to NOV in NRC IR 92-16 (8/5/92), PG&E Exhibit 27, Enclosure 1 at 1,2.

623- NRC issued a Severity Level IV violation regarding PG&E's incorrect use of chainfalls while lifting primary and secondary lids of a radwaste container. Id., Enclosure 1 at 1.

624- PG&E determined the root cause of the incident to be personnel error. The seating of the primary cask lid using chainfalls was outside of the job scope and in violation of AP C-702. PG&E found a contributing cause to be a weakness of rigging instructions in MP M-50.23, which does not provide guidance for manipulating the load in place and subsequently seating the cask lid. Id., Enclosure 1 at 2.

**625- Finding: Maintenance personnel were involved in this activity.**

626- PG&E claims that "the incident regarding the chainfalls has no bearing on maintenance, it wasn't maintenance personnel and it wasn't a maintenance activity." Tr. at 1640. Yet, the Board observes that maintenance personnel were, in fact, involved. Maintenance personnel were involved in the supervision of the activity: "A Mechanical Maintenance (MM) foreman supervised this rigging activity while the radioactive material was being placed in the cask and until the rigging was attached to the cask lids..." PG&E Exhibit 27, Enclosure 1 at 2. Maintenance personnel were involved in the corrective actions that were taken:

> The MM general foreman discussed with the responsible foreman the Plant Manager's previous policy memo regarding tailboard requirements... The MM general foreman conducted a meeting with MM craft personnel stressing the importance of tailboards and stopping work when outside the scope of a tailboard... The Maintenance Services Manager will discuss industrial safety with the riggers to further emphasize the importance of proper rigging, personnel safety practices, and the stopping of work when required activities are outside the pre-job tailboard scope. Id. at 2.

The Board finds not only that this is a maintenance problem but that PG&E's insistence that it is not maintenance-related is yet another indication of a programmatic problem at DCNPP, which is the poor coordination and recognition of shared responsibility between maintenance and other departments. See Lack of Communication and/or Coordination.

**627- Finding: The chainfall incident presented a threat to personnel safety.**

628- PG&E claims that the incident involving the incorrect use of chainfalls "did not present a threat to personnel safety." PG&E Exhibit 27, Enclosure 2 at 1. Yet, the NRC specifically stated in its Inspection Report: "This was a personnel safety issue... the individual standing on the cask lid could have been seriously hurt if the chain had parted." NRC IR 92-16 (7/7/92), MFP Exhibit 137 at 4. We find the regulatory agency to be less self-interested, more experienced, and thus more credible on this issue.

**629- Finding: PG&E has exhibited a weakness in its safe control of lifting and rigging devices for heavy loads.**

630- The NRC has expressed a concern that the violation indicated a weakness in PG&E's control of lifting and rigging devices for heavy loads, particularly in light of a rigging problem in 1991 involving a loss of offsite power caused by a mobile crane boom that came too close to the 500 kV lines. PG&E Exhibit 137, Enclosure 2 at 1. "The inspector acknowledged that two different groups of personnel were involved, but noted that both events appeared to involve weakness in the preplanning and control of lifting or rigging activities." Id. at 4.

631- PG&E has challenged the commonality of the two events, but acknowledged the importance of proper crane operation and compliance with plant procedures. PG&E Exhibit 137, Enclosure 2 at 1.

632- The Licensing Board finds that these two incidents are related in that both involve:

1. lifting and rigging devices for heavy loads;
2. violation of plant procedures and/or rules;
3. personnel errors;
4. maintenance personnel;
5. a threat to personnel safety;
6. ineffective management systems;
7. weakness in planning the activity.

633- The Board concludes that these two incidents share some pertinent characteristics, and thus they demonstrate a deficiency in PG&E's ability to safely control lifting and rigging devices for heavy loads at DCNPP.

<u>MAIN FEEDWATER PUMP OVERSPEED TRIP DUE TO FAILURE OF POWER SUPPLY TO SPEED SENSING PROBES</u>

MFP Exhibit 138: NCR DC1-92-EM-N010 (7/29/92)
MFP Exhibit 139: NRC IR 92-05 (4/17/92)
MFP Exhibit 140: NRC Management Meeting, Report 92-13 (4/16/92)
MFP Exhibit 140A: LER 1-92-002-00 (4/3/92)
MFP Exhibit 142: NCR DC1-91-TI-N045 (6/10/91)

Transcript pages: 1647-1666,2217,2219,2244-2247

<u>Problems with the Main Feedwater Pump Inverter</u>

634- On March 6, 1992 a reactor trip was initiated as a result of a low-low level on the 1-3 Steam Generator. The low-low level steam generator condition was caused by a MFW pump 1-1 trip. The inverter feeding both speed channels on the 1-1 main feedwater (MFW) pump failed, an automatic transfer to inverter associated with the 1-2 MFW pump failed to automatically occur and power was lost to both speed channels on the 1-1 MFW pump. The loss of the speed channel caused the 1-1 MFW pump to go to a maximum speed condition which resulted in the MFW pump trip. NCR DC1-92-EM-N010 (7/29/92), MFP Exhibit 138 at 1-4.

635- PG&E determined that the root cause of this event was that the original PG&E power supply design (pre-1989) for the Lovejoy speed probes was a single channel design which was inconsistent with the overall dual channel design philosophy of the Lovejoy system. This problem was initially identified in 1986 in a letter (2/27/86) written by a technician addressing the potential for loss of both speed channels due to the loss of a single power supply. This letter was never answered. Id. at 10.

636- A contributory cause of the event was noted. The design of the power supply to the MFP speed probes included an automatic transfer to the power supply for MFP 1-2. The transfer scheme utilized relays to accomplish the switching. One of the relays had a small piece of insulating debris lodged between one of the contact surfaces, which prevented a successful transfer. NRC Management Meeting, Report 92-13 (4/16/92), MFP Exhibit 140A at 4.

637- The failed inverter in this event was IYFW11, Abacus Controls Inc., Model #452-4-125-M-NMN. "Results of the event investigation showed that this type of inverter has experienced similar failures in the past." MFP Exhibit 140A at 4. There has been documentation demonstrating a "significant problem with heat building in the card cage..." and the lugs in the transfer relay too big to fit into the terminal relay. MFP Exhibit 138 at 9.

638- The MFW inverters were installed in November of 1989.

* The first failure occurred on inverter IYFW22 on 5/27/90. The transistors were replaced. MFP Exhibit 138 at 2.
* The second failure occurred on inverter IYFW21 on 6/27/90 and a new inverter from the warehouse stock was installed. The failed inverter was repaired and returned to the warehouse. Id.
* The third failure occurred on IFW12 on 4/25/91 and a new inverter from the warehouse was installed. The failed inverter was repaired and returned to the warehouse. Id.
* The fourth failure occurred on IYFW11 on 5/18/91 and an inverter from the warehouse was installed. The failed inverter was sent to Abacus Controls for analysis. Abacus determined that the power supply card had failed and was designed for operation from 200-250 VDC source; while the one being used is supplied by 135 VDC. Their solution to this

design flaw was to change the value of R2 in all 120 VDC power supply cards. Id.

* The fifth failure occurred on inverter IFW21 on 10/20/91 and an inverter from the warehouse was installed. Id. at 3.

* The sixth failure occurred on inverter IYFW22 on 10/26/91 and an inverter from the warehouse was installed. Abacus determined that this failure was due to the power module and not related to the previous power supply card failures. Id.

* The seventh failure occurred on inverter IFW11 on 12/3/91, "and also a failure to transfer due to the relay contacts being miswired." Id. Two driver cards and a power module were replaced. On 12/5/91, Abacus Controls stated that they were upgrading the 452-4-125-M-NMN which would have the R3 upgraded, remove R4 through R7 from the driver card and mount equivalent resistance in the open area of the chassis. Id.

* The eighth failure occurred on inverter IYFW12 on 12/28/91, and an inverter from the warehouse with the R3 upgrade was installed. By 1/30/92, all inverters in service and power supply cards in stock were upgraded. Id.

* The ninth failure occurred on inverter IYFW11 on 3/6/92 (this event). An operator dropped a grate adjacent to the inverter panel and a solder connection opened up, causing excessive current to be drawn blowing both DC input fuses. The auto transfer also failed because of debris in a relay contact which resulted in loss of power to both Lovejoy speed probes and tripped the feedwater pump. Id. at 4.

639- Other systems were affected during this event, two failing to operate as designed. First, three of the four 10% steam dump valves (to the atmosphere) opened after the reactor trip. Second, Diesel Generator 1-1 started. NRC IR 92-05 (4/17/92), MFP Exhibit 139 at 4,5.

Failure of the Track and Hold Board

640- A previous event occurred on 4/23/91 involving a reactor trip from a turbine trip due to high steam generator level. PG&E determined that the root cause was the failure of an operational amplifier U1 in the MFW pump 1-1 speed controller "track and hold board" circuit board of the Lovejoy feedwater pump control system. This caused the pump speed to increase until "low selected" at the preset level of the manual start up station. This sudden increase in feedwater pump speed overfed steam generator 1-3 due to the selected mode of valve control resulting in a high level P-14 actuation causing a turbine trip and reactor trip. NCR DC1-91-TI-N045 (6/10/91), MFP Exhibit 142 at 5.

641- On 5/30/90, a near miss occurred due to a similar "track and hold" card failure. Similar occurrences have happened at Zion 2, LaSalle 2 and Indian Point 2. Id. at 7.

642- As "prudent" action, the TRG recommended that the Lovejoy speed control system be replaced "to improve overall plant reliability." Id.

**643- Finding: Inverter failure was a long standing problem at DCNPP. PG&E's corrective actions were ineffective in preventing the repeated recurrence of these failures.**

644- PG&E has a long history of failed attempts to repair the feedwater pump inverter problems. As PG&E conceded, "after troubleshooting and repair by the vendor and plant technicians, the inverter failed again. As a result, design modifications were made to correct the cause of these failures, but subsequent failures were experienced from other causes." LER 1-92-002-00 (4/3/92), MFP Exhibit 140A at 4.

645- An NRC inspector "reviewed the past history of feedwater pump inverter failures. This review indicated that there have been several inverter failures in the past which appear to be indicative of a long standing problem." MFP Exhibit 139 at 6.

646- PG&E identified two important issues regarding this event: timeliness and previous corrective actions on inverter failures. "One thing needs to be considered is that we should have written off the power supply and get a different power source." MFP Exhibit 138 at 18.

647- PG&E admitted that "there was a tendency to try to make the design work instead of looking and reassessing the design. We waited too long and continued to try to fix it when it failed instead of just putting in a new design." Tr. at 1652. PG&E also noted as a lesson learned: "when you see multiple failures, redesign." MFP Exhibit 138 at 19.

**648- Finding: Financial consideration influenced PG&E's corrective action.**

649- PG&E conceded that "in the previous failures the reason we did not change the power supply was because of money." Id. at 18. The Licensing Board notes that with DNCPP's unique rate payer settlement, the cost of maintenance cannot be passed onto the rate payers. This fact influences the "priority list" of repairs that is utilized by PG&E management. Tr. at 814. Furthermore, financial decisions that are made do not necessarily contribute to the protection of the health and safety of the public.

**650- Finding: PG&E's response to these main feedwater pump inverter failures was untimely and inefficient.**

651- A management meeting was held on 4/2/92 to discuss recent CFCU BD failures and MFW pump inverter failures. The NRC stated that these problems "illustrate that your staff is not always resolving indications of system problems in a prompt, thorough manner. The timeliness of your corrective actions for known problems has been a past issue of concern." NRC Management Meeting, Report 92-13 (4/16/92), MFP Exhibit 140, cover letter.

652- During the meeting, G. Rueger (PG&E Senior Vice President, Nuclear Power Generation) stated that

> PG&E may have been too narrowly focused on the issue, causing PG&E to fix the existing equipment, rather than to question the adequacy of the design after repeated failures. Mr. Fujimoto [PG&E Vice President, General Engineering and Construction] noted that since the equipment had been redesigned in February, 1989, there

> was a tendency to continue to try to make the new design work, rather than reassess the design. Mr. Martin [NRC Regional Administrator] observed that it was not typical of a strong engineering organization to wait for several failures to fix a deficient design, particularly in the case of these failures... He noted that the December 3, 1991, failure should have raised serious concerns, and should have been dealt with more forcefully. Each action PG&E took may have appeared reasonable when considered individually, but not in perspective with the whole issue. Although these particular components were not safety-related, there is a need to come to terms with timely corrective action for these situations before problems arise with higher safety significance. Id. at 3.

PG&E admitted that "there was a tendency to try to make the design work instead of looking and reassessing the design. We waited too long and continued to try to fix it when it failed instead of just putting in a new design." Tr. at 1652.

653- Important questions were raised during a TRG meeting: "why in 1989 when we performed the FMEA on this design we did not catch this problem?" MFP Exhibit 138 at 20. And in regards to the unanswered letter written in 1986 by a technician addressing the potential for loss of both speed channels due to the loss of a single power supply: "when somebody addressed a concern why was no action taken?" Id. at 22.

**654- Finding: Problems with the main feedwater pump introduces a possibility of a plant transient, although it is nonsafety equipment.**

655- PG&E claims that there is no safety significance to the inverter failures because "the main feedwater pump is a nonsafety related piece of equipment." Tr. at 1653. Yet, PG&E also admits that "the feedwater pumps and the feedwater control system is probably the single most cause of trips throughout the nuclear power industry." Tr. at 1659. The NRC also notes that the main feedwater pump introduces a possibility of a plant transient, even though it is nonsafety equipment. Tr. at 2219.

656- Additionally, the design is such that if one inverter loses power, it will automatically transfer to the inverter for the other pump. Yet, there were two instances in which the transfer mechanism didn't work and power was lost to the main feedwater pump. Tr. at 1654,1655.

657- The Licensing Board finds that PG&E took an unreasonably long time to resolve the issue of the main feedwater pump inverter failures. The likelihood of this problem causing repeated reactor trips should have been incentive enough to remedy the situation in a more efficient and timely fashion. Additionally, we find that this series of incidents demonstrates other significant problems with PG&E's maintenance and surveillance program: failure to address concerns that were raised in 1986, undue financial considerations discouraging corrective action, the presence of foreign debris which hampered the operability of the inverters. See also Untimely or Ineffective Response to Maintenance Problems in the General Findings.

CONTAINMENT VENTILATION ISOLATION (CVI)

MFP Exhibit 144: LER 1-92-005-01 (7/20/92)
MFP Exhibit 145: NCR DC1-92-TI-N020 (6/24/92)
MFP Exhibit 146: LER 1-91-013-00 (9/6/91)
MFP Exhibit 146A:NCR DC1-91-TI-N068 (10/3/91)
MFP Exhibit 147: LER 2-91-001-00 (8/13/91)
MFP Exhibit 148: NCR DC2-91-TI-N062 (8/9/91)
MFP Exhibit 149: LER 1-91-006-00 (4/25/91)
MFP Exhibit 149A:NCR DC1-91-EM-N041 (4/25/91)
MFP Exhibit 150: LER 1-90-019-00 (1/28/91)
MFP Exhibit 150A:NCR DC1-90-WP-N093 (1/18/91)
MFP Exhibit 151: LER 2-90-004-00 (5/17/90)
MFP Exhibit 151A:NCR DC2-90-TI-N025 (10/11/90)

Transcript pages: 1667-1681
PG&E Testimony: 69 (radiation monitoring)

658- PG&E has acknowledged, "CVIs occur more frequently at DCPP than at any other US power reactor... The root cause for most of the CVIs has been personnel error..." NCR DC1-91-TI-N068 (10/3/91), MFP Exhibit 146A at 11.

CVIs due to Personnel Error

**Test probe:**

659- A CVI and a fuel handling building ventilation system shift from normal mode to iodine removal mode (an ESF) was actuated on 4/17/90 when a voltage transient occurred. LER 2-90-004-00 (5/17/90), MFP Exhibit 151 at 2. PG&E found that the root cause was personnel error. An I&C technician had allowed a test probe to slip during troubleshooting and caused a short, resulting in a voltage transient. Id. at 4.

**Pliers:**

660- On 12/27/90, while performing design modifications in radiation monitor cabinet RMRMA, a craftsperson was bending a smoke detector brace. During removal of the channel lock pliers from the cabinet, the pliers came in contact with the terminals on fuse block RM-5, thus causing a voltage transient and a containment ventilation isolation (CVI) signal. The electrician was aware that the panel was energized. LER 1-90-019-00 (1/28/91), MFP Exhibit 150 at 2.

661- PG&E determined the root cause to be personnel error; if the electrician had taped the tool in accordance with standard work practices used by I&C, contact with the fuse block may not have occurred. PG&E found a contributory cause to be the failure to share maintenance bulletin #007 with the electrician. This bulletin reviewed precautions when doing work on energized equipment - such as taping tools. NCR DC1-90-WP-N093 (1/18/91), MFP Exhibit 150A at 5.

662- The minutes from the TRG meeting raised the question: should the pliers have been rubber coated? Additionally, the electrician involved in the event was interviewed; he stated that he should have used a smaller pliers and worked from the front of the cabinet. Id. at 10,11.

**663- Finding: Corrective action taken by PG&E for previous similar events were ineffective.**

664- Numerous previous similar events have occurred, thus warning PG&E of this problem. PG&E also took corrective actions that should have prevented the incident involving the pliers, but they failed to do so. NCR DC2-91-TI-N062 (8/9/91), MFP Exhibit 148 at 10. One of the corrective actions taken included the issuance of a maintenance bulletin to reemphasize the need for caution when working on energized equipment. Id. However, maintenance bulletins were not being distributed to general construction (GC) at the time this bulletin was issued, so the corrective action failed to prevent the recurrence of this event. NCR DC1-90-WP-N093 (1/18/91), MFP Exhibit 150A at 8.

**665- Finding: This incident shows a lack of communication and coordination between maintenance and other departments.**

666- PG&E acknowledges that "there is no plant or GC procedure specifically regarding work on energized equipment." Yet, PG&E feels that no formal procedure is needed, as precautions against energized equipment are common knowledge to journeyman electricians, and maintenance bulletins are adequate to disseminate additional guidance." Id. at 12.

667- The Licensing Board disagrees. We find that the mere occurrence of this incident is enough to warrant stronger protective measures. Additionally, we note that the "maintenance bulletins" were not made available to GC personnel, this to be further evidence that the maintenance department does not adequately communicate or coordinate with other departments. See Lack of Communication and/or Coordination in General Findings.

**Screw:**

668- On 7/15/91, another CVI occurred. An I&C technician inadvertently dropped a screw onto the power switch for NM51 while performing maintenance. The screw fell off of a "holding" screwdriver; a tool designed to hold the screw while it is being inserted. The screw fell through the cabinet and came in contact with unused contacts on the power supply switch. This resulted in a voltage transient to the output relays of radiation monitors RM-11 and RM-12, which caused an SSPS train B CVI actuation. LER 2-91-001-00 (8/13/91), MFP Exhibit 147 at 2.

669- PG&E determined the root cause of the CVI to be personnel error, i.e., inattention to detail, in that the I&C technician did not establish a temporary electrical barrier while working above the energized switch. "It is common practice for technicians to establish temporary electrical barriers when working on or near energized equipment, when practical." MFP Exhibit 148 at 7. The technician was aware that the equipment was energized and only later recognized that it would have been possible to barricade the switch and have prevented the incident. LER 1-91-006-00 (4/25/91), MFP Exhibit 149 at 6.

**670- Finding: Financial considerations was a factor in the determination of corrective action taken.**

671- In the TRG minutes, a discussion on how the screw fell in the opening of the switch cover was noted. It was suggested that a cover with no opening would be a good idea, but that it "requires a DCN [and] that is not economically practical." MFP Exhibit 148 at 15.

672- PG&E acknowledged that it would be possible to permanently insulate the switches, but the "low probability of occurrence does not justify cost of insulating all similar switches." PG&E further claimed that "it is the responsibility of personnel working in these cabinets to be alert and careful not to cause inadvertent equipment actuations. This technician was properly trained in the use of equipment and procedures." Id. at 7.

673- It is known that with DNCPP's unique rate payers settlement, the cost of maintenance cannot be passed onto the rate payers. The Licensing Board finds that this fact influences the "priority list" that is utilized by PG&E management to determine what maintenance is to be performed. Tr. at 814. Furthermore, financial decisions that are made - as in this case - do not necessarily contribute to the protection of the health and safety of the public. See also Financial Considerations in the General Findings.

**674- Finding: Corrective action taken by PG&E for previous similar events were ineffective.**

675- Again, PG&E acknowledges that

> there is no plant or GC procedure specifically regarding work on energized equipment." Yet, PG&E feels that no formal procedure is needed, as precautions against energized equipment are common knowledge to journeyman electricians, and maintenance bulletins are adequate to disseminate additional guidance. MFP Exhibit 150A at 12.

676- But the Licensing Board observes that the well-trained technician involved in this event was not careful, did not barricade the switch and therefore caused an inadvertent CVI. Additionally, the multitude of previous similar events indicates that additional corrective action needs to be taken.

677- Three of the seven similar previous events noted in MFP Exhibit 147 involved a voltage transient that resulted in a safety system actuation <u>and</u> failure of personnel to utilize caution when working on energized equipment. In two of these, PG&E, itself, acknowledged that "re-emphasis" of the importance of adherence to work practices regarding caution when working near energized equipment is warranted. MFP Exhibit 147 at 4-6.

**Incorrectly installed jumper:**

678- On 8/10/91, another CVI occurred while a technician was installing a jumper in a process control rack. Two technicians were requested to defeat a continually alarming annunciator. They correctly assumed that the relay was located in annunciator panel PK007, but were unable to identify a suitable jumper location. One of the technicians left to further investigate the drawings (in accordance with I&C guidelines) and the other contacted the control room. Once in contact with the control room, the technician told the operator that he was going to install a jumper between the terminals and asked the operator to tell him if the annunciator light cleared or remained lit. (I&C guidance prohibits proceeding with an action when unsure of the result of the actions, such as installing a jumper when unsure if an annunciator will clear.) This technician installed a jumper while in phone communication with the Unit 1 control operator. While installing the jumper, an arc was drawn across the terminals and the technician was informed by the control operator that numerous alarms and a CVI had occurred. The technician then removed the jumper. NCR DC1-91-TI-N068 (10/3/91), MFP Exhibit 146A at 2,3.

679- PG&E determined the root cause of the event to be personnel error, i.e., failure to follow procedures, in that an I&C technician incorrectly installed a jumper without complete knowledge of the results of the action. PG&E found that a contributory cause of the event was failure to follow AP C-154; the specific actions necessary to bring in the annunciator light solid were not identified prior to the beginning of the work. "The SFM and the technicians discussed the general step required and the possible relays to work with, but had not decided on the specific relay to work. The Shift Supervisor is required to sign the AP C-154 approval, and did not." Id. at 5,6.

**680- Finding: The personnel involved in this event failed to adhere to procedure and policy guidelines.**

681- The Licensing Board finds this incident to be another example where maintenance personnel is unprepared for the task. We find it disturbing that these technicians failed to follow AP C-154 and failed to adhere to I&C policy stating that work should be stopped when an individual is unsure of the results of actions.

<u>CVIs due to Faulty Radiation Monitoring Equipment</u>

**Seized pump:**

682- On 3/26/91, during performance of a surveillance procedure, an attempt was made to start the pump for RM-11, the containment air particulate monitor. This start attempt resulted in a bus ground due to a faulted sample pump motor and a spurious high radiation alarm from RM-11. The high radiation alarm caused a CVI. NCR DC1-91-EM-N041 (4/25/91), MFP Exhibit 149A at 1.

683- PG&E found that the immediate cause of the event was due to equipment failure; the sample pump seized and stalled the motor. The locked rotor current overheated the motor stator insulation and arced to ground, inducing a spurious high radiation signal in the RM-11 detector. PG&E's review of the maintenance history showed that this motor has had similar failures in the past. <u>Id.</u> at 2. The pump and motor failure occurred after only five months of operation. <u>Id.</u> at 7. It was additionally noted that "the RM-11 radiation monitor pump and motor combination do not appear to be suitable for continuous service in an elevated temperature environment." <u>Id.</u> at 4,5. "The thermal overloads were removed from the sample pump motors in the early to mid 1980s." NECS was asked for a recommendation as to leaving the thermal overloads off of the motors; its preliminary response was that the thermal overloads should be replaced. Id. at 10.

**684- Finding: PG&E's response to its deficient radiation monitoring system is untimely.**

685- PG&E found the root cause of the event to be the fact that the radiation monitoring system detectors are overly sensitive to electrical noise and radio frequency energy. This system "has demonstrated this sensitivity to electronic noise since the Units have been operating. The power circuit for the motor is in close proximity to the electronic leads for the RM-11 monitor. A number of events have resulted from this sensitivity... An upgrade program for the radiation monitoring system is underway." MFP Exhibit 149A at 5. In its letter dated October 2, 1989 (DCL-89-254), PG&E acknowledged its problems regarding the effects of power transients on CVI-related radiation monitors. At that time, PG&E claimed that it had initiated a Radiation Monitor System upgrade program to replace existing radiation monitors with equipment that is less sensitive to power transients. MFP Exhibit 151 at 6. In 1993, PG&E continues to make that same claim. In fact, PG&E claims that this work is scheduled to be completed by 1995. PG&E Ts. at 69.

686- The Licensing Board finds that PG&E has been aware of its troublesome radiation monitors for a substantial amount of time; yet it is slow to remedy this situation. The Board finds this delay indicative of a maintenance program that is insufficiently responsive to long standing problems. Given PG&E's recalcitrance on this issue, we find that the extension of its license cannot be approved until PG&E has confirmed that its proposed corrective actions have been completed.

**Loose connector:**

687- NCR DC1-92-TI-N020 and LER 1-92-005-01 addressed the CVI that occurred in Unit 1 on 4/28/92. Although no high radiation conditions existed, radiation monitor RM-14B exceeded its alarm setpoint. PG&E determined the root cause of this event to be a loose connector on the test box being used on RM-28B at the time of the event. The loose connector resulted in generation of electronic noise in the circuitry of RM-14B which ultimately led to the CVI. LER 1-92-005-01 (7/20/92), MFP Exhibit 144 at 1. In the TRG minutes, it was noted that PG&E considered replacing the test boxes, "but since the radiation monitors and system will be upgraded in the near future, the test boxes will no longer be needed." Therefore, no corrective action was taken. NCR DC1-92-TI-N020 (6/24/92), MFP Exhibit 145 at 14.

688- In conclusion, the numerous similar events noted in these documents confirm the fact that many CVIs occur at DCNPP and that these CVIs result from a variety of causes. Moreover, they occur repeatedly, despite repeated attempts to prevent them.

689- PG&E claims that these occurrences are "benign;" they do not challenge the operations crew nor cause any significant wear and tear on the equipment. Tr. at 1670-1672. CVIs are unintentional events, however. And when such events are found to be repeatedly occurring, one must question why. The Licensing Board has noted that many of these CVIs have been caused by personnel error - by carelessness, lack of knowledge or failure to adhere to procedure. The majority of others are initiated due to the deficiencies in the equipment. But we find, too, that other factors are often involved. In one case in which equipment failure was determined to be the cause, the adequacy of preventive maintenance and the operating environment was called into question. Financial considerations have also been implicated. Improper maintenance may have affected another incident. The Board thus concludes that the sheer number of such unplanned events involving an important safety feature creates concern. The Board finds that this evidence demonstrates an unacceptable level of deficiencies in the maintenance and surveillance organization at DCNPP.

REACTOR TRIP ON STEAM GENERATOR LOW LEVEL

MFP Exhibit 155: LER 1-91-002-01 (5/17/91)
MFP Exhibit 156: NCR DC1-91-WP-N012 (5/13/91)

Transcript pages: 1691-1703

690- On 2/1/91, a Unit 1 reactor trip occurred due to steam generator (SG) low level with a steam flow/feedwater flow mismatch on SG 1-4. The trip was caused by personnel error. Valve AIR-I-1041 was inadvertently closed by personnel erecting scaffolding in the area. The closed valve isolated instrument air supply to the main feedwater regulating and bypass valves FCV-530, 540, 1530 and 1540. The regulating and bypass valves failed closed on loss of instrument air, isolating feedwater flow to two SGs. SG levels decreased and the unit tripped. LER 1-91-002-01 (5/17/91), MFP Exhibit 155 at 1.

691- Contributory causes of the event include the following:

1. There was a new management directive that outage-related work not be performed before the outage unless it was on the pre-outage schedule. Work that may affect safety-related components is not allowed to be put on the pre-outage schedule. Mechanical Maintenance failed to follow this procedure, however, when it started the work early, even though it was not on the pre-outage schedule. NCR DC1-91-WP-N012 (5/13/91), MFP Exhibit 156 at 8.
2. AP C-59 did not provide adequate barriers against erecting scaffolding around sensitive plant equipment during operation. Id. at 9.
3. The design of the instrument air isolation valve is such that it requires a 90 degree rotation to move to the closed position. Although the handle is near a wall and not easily accessible, it can be closed accidentally. Id.

692- Additionally, the following equipment did not function properly during the trip or trip recovery:

1. Circulating Water Pump (CWP) 1-1 failed to restart following the 12kV bus power transfer to start-up.

2. 25kV Motor Operated Disconnect (MOD) switch did not open fully from the control room switch. It had to be manually opened to the full position to complete the electrical system alignment for backfeeding.

3. Control Rod Drive Mechanism (CRDM) Fan E-13 failed to restart following the power transfer.

4. The Main Turbine Stop Valve FCV-145 did not fully close.

MFP Exhibit 156 at 3-5.

**693- Finding: Multiple maintenance deficiencies were involved in the 1991 maintenance caused reactor trip. These include personnel error, deficient planning, equipment weaknesses, insufficient maintenance, communication and procedure inadequacies.**

694- The personnel error that initiated this chain of events occurred while a carpenter was carrying planks on the scaffolding structure; one inadvertently closed valve AIR-I-1041. Tr. at 1692,1693. Other deficiencies that conspired to create this situation involved the following:

A. <u>Inadequate planning of the erection of the scaffolding:</u>

695- "The scaffolding request was not fully completed. The dates by which the scaffolding was required were not filled in and the request was not marked as 'outage,' 'pre-outage,' or 'non-outage' work... The sketch on this scaffolding form did not provide sufficient detail to show the exact location where the scaffolding was to be erected." MFP Exhibit 155 at 2.

B. Procedure deficiency:

696- "AP C-59 requires enhancements in order to be effective." MFP Exhibit 156 at 7.

> "AP C-59 did not provide adequate barriers against erecting scaffolding around sensitive plant equipment during operation. Specifically, AP C-59 did not define sensitive equipment that would require additional review, did not adequately identify components to be worked, did not specify responsibilities for completing the scaffolding request form, and did not identify the allowed start date or plant modes for the work." MFP Exhibit 156 at 9.

> "In addition, C-59 has a requirement that scaffolding not be erected within 50 feet of main feedwater pumps without additional review and approval, but does not provide a specific list of other critical or sensitive equipment areas." Id. at 17.

C. Ineffective communication:

697- "The issues of outage vs. pre-outage scheduling and deficiencies... could have prevented the event." Id. However, "plant management's new policy to ensure that no work would be done before the outage without first being reviewed on the pre-outage daily schedule was not formally written down or effectively communicated to all applicable personnel." Id. at 7.

D. Equipment weaknesses:

698- (1) CWP 1-1 failed to automatically restart following the 12kV bus power transfer to startup power. It was noted that "the failure of CWP 1-1 and other recent failures of the CWPs to auto-restart cause the reliability of the CWPs to be questioned." MFP Exhibit 156 at 9. Its failure has been subsequently determined to be due to a faulty electrical relay. Tr. at 1699.

699- (2) The 25 kV MOD switch did not open fully. In preparation for outage work on the MOD, plastic sheeting had been taped to the MOD manual drive shaft and switch actuating shaft. When the MOD was signaled to open, the turning drive shaft began to wrap the attached plastic around the shaft. The shaft continued to turn until enough plastic had accumulated to contact the nearby switch actuating shaft. Continued wrapping forced the switch actuating shaft outward, simulating "stop logic," which de-energized the MOD power and control circuit. MFP Exhibit 155 at 3,4.

700- (3) CRDM Fan E13 failed to restart following the power transfer. "Electrical Maintenance believes that a combination of reduced component part clearances due to age-related shrinkage and dimensional changes resulting from elevated operating temperatures caused the magnetic starter to fail." Id. at 4.

E. Lack of preventive maintenance:

701- Following the trip, the Main Turbine Stop Valve FCV-145 did not fully close. Stroke time was very slow (in excess of two minutes) due to a very dry and scored brass bushing on the actuator spring can assembly. No preventive maintenance activity had existed to lubricate the bushing. MFP Exhibit 155 at 4, MFP Exhibit 156 at 5, Tr. at 1700.

**702- Finding: PG&E's previous corrective action to protect sensitive plant equipment where scaffolding is being erected was ineffective to prevent damage to sensitive equipment.**

703- NCR DC2-90-WP-N004 addressed a previous similar event where scaffolding was erected without appropriate controls. Corrective actions for that event included issuance of a new administrative procedure (AP C-59). However, this "procedure did not provide adequate barriers to prevent the current event." MFP Exhibit 156 at 13. "AP C-59 did not provide adequate barriers against erecting scaffolding around sensitive plant equipment during operation. Specifically, AP C-59 did not define sensitive equipment that would require additional review, did not adequately identify components to be worked, did not specify responsibilities for completing the scaffolding request form, and did not identify the allowed start date or plant modes for the work." Id. at 9.

704- The Licensing Board finds that the failure of any individual component (i.e. valve AIR-I-1041) presents some concern regarding the adequacy of maintenance of their components. However, when such an incident is associated with multiple failures and deficiencies, as we observe in this instance, a much more significant safety concern arises. In this case, multiple barriers were broken that could have prevented the initiating event. In fact, the event occurred despite actions taken as a result of a previous similar event. Additionally, a variety of other deficiencies existed that created a situation in which a multitude of systems and functions became involved in a chain of failures. The Board finds this event to be indicative of substantial and multiple inadequacies in PG&E's maintenance and surveillance program at DCNPP. The Board is additionally disturbed by the fact that PG&E has inappropriately expressed no concern for the multiple failures that occurred during this event. Tr. at 1695. See General Findings for discussion regarding Personnel Errors.

AUXILIARY SALTWATER PUMP CROSSTIE VALVE

MFP Exhibit 168: NCR DCO-91-EM-N009 (11/22/91)

Transcript pages: 1713-1745

705- As described by PG&E in NCR DCO-91-EM-N009 (November 22, 1991), (MFP Exhibit 168), the Auxiliary Saltwater (ASW) System

> functions to transfer the combined heat load from structures, systems, and components important to safety to the ultimate heat sink under normal and accident conditions. Assuming a single failure, redundancy is provided to assure that this safety function will be accomplished. [ASW crosstie valves] FCV-495 and FCV-496, which remain open during normal operation and during the injection and cold leg recirculation phases of an event, function to provide train separation in support of the long term recirculation phase of post-accident operation. Closure of either FCV-495 or FCV-496 is required to achieve ASW train separation. <u>In the event of loss of power or control signal such that the motor operators were unable to function, these valves will fail open and manual operation would be required to provide train separation.</u>" MFP Exhibit 168 at 7 (emphasis added).

We note that there is some contradiction in the testimony regarding the safety significance of the ASW crosstie valves. PG&E witness Giffin stated that "the function of closing the valve is not safety significant." Tr. at 1725. But PG&E witness Vosburg testified that the closing of the crosstie valve <u>is</u> a safety function. Tr. at 1718. It is clear to us from PG&E's NCR that the closing of this valve is required for the safe operation of the plant during a passive line break following an accident; thus, it is a safety function under those conditions.

**706- Finding: PG&E's failure to include manual testing of the ASW crosstie valves in its maintenance and surveillance program reflects a basic inadequacy in the program.**

707- As a result of the incident described in this NCR, PG&E now provides for manual testing of the ASW crosstie valves every 92 days. The Board finds that this is an unacceptably late response to a problem that should have been clear several years ago. Moreover, we find that PG&E's analysis of the problem reflects a fundamental misunderstanding of or disregard for basic concepts of nuclear reactor safety, and thus causes us to question whether this faulty analysis may be applied in other parts of PG&E's maintenance program.

708- First, PG&E has been well aware that the intake structure is a harsh environment where safety components are particularly subject to corrosion and degradation. Id. at 6. Indeed, PG&E had documented "material degradation" of the valves as early as 1981 (SW-1-FCV-495) and 1988 and 1989 (SW-1-FCV-496). Id. PG&E also knew that its design basis required that the handwheels on these valves be manually operable in post-accident conditions. Yet, PG&E took no steps to assure the manual operability of these valves until the most recent incident occurred in 1990.

709- Second, PG&E's safety analysis, in defending its performance regarding this issue, was erroneous and inconsistent. In its safety analysis of the event, PG&E

reasoned the public health and safety was not affected by the manual inoperability of the valve operator, in part because it could be operated electrically from the control room. Id. at 8. However, as previously acknowledged in the same NCR, the electrical operator cannot be relied on during or after an accident, because it must be assumed that offsite power is unavailable. Id. at 7.

710- PG&E's safety analysis also stated that public safety was protected because "maintenance personnel demonstrated that the valves could be manually operated within the time window allowed for closure of the valves," i.e., 11 hours. Id. at 6,15. While PG&E is not specific, it appears that the freeing of FCV-495 appears to have taken a relatively short time. However, with respect to the other valve, FCV-496, the effort took much longer. On September 14, 1990, PG&E tried to "free the handwheel without disassembly of the valve," but reported that "all attempts fail." Id. at 2. "Further efforts were not attempted because sufficient parts were not available for an overhaul at the time." Id. On January 16, 1991, PG&E tried again to free the handwheel. Id. at 3. The effort - which took "copious quantities of penetrating oil, picks, emery paper and hacksaw blades" - took from sometime during the swing shift that day to "around mid-day on January 17, 1991." Id. Although the amount of time this took is not specified, it appears to have been a minimum of 12 hours, and a maximum of 16 hours.

711- This brings us to the third failing in PG&E's reasoning, which was to attribute "low safety significance" to the failure of manual operator FCV-496 because the other manual operator, 1-SW-FCV-495, was able to function, presumably within 11 hours of trying to close it. Clearly, the purpose of PG&E's maintenance program was to provide a reasonable assurance that <u>both</u> valve operators would be functional during an accident. In the absence of any program to manually test either operator, PG&E was just plain lucky that one of them worked. This reliance on pure chance in lieu of verifying the reliability of a safety function can hardly be termed insignificant.

712- We find that PG&E's safety analysis of this event indicates fundamental inadequacies in its perception of the role of maintenance and surveillance in assuring that DCNPP is operated safely. We are concerned that these inadequacies have not only adversely affected the quality of PG&E's judgments with respect to the adequacy of the maintenance and surveillance program for the ASW crosstie valves, but that they affect PG&E's judgments and decisions across the board. Accordingly, we find that PG&E's maintenance and surveillance program is inadequate with respect to PG&E's fundamental disregard for the principle that one of the key purposes of a maintenance and surveillance program is to maintain the redundancy of safety systems.

713- On 6/29/90, PG&E determined the manual handwheel for the ASW pump crosstie valve SW-1-FCV-496 was not manually operable due to extensive rust. Id. at 1. It was capable of remote operation from the control room (Tr. at 1714), yet manual operation of this valve may be required to support the long term recirculation phase of post-accident operation. Id. On January 18, 1990, SW-1-FCV-495, the other ASW crosstie valve, was found to be "inhibited from manual operation due to excess paint between the handwheel and actuator frame." Id. at 4.

714- PG&E verifies that the crosstie valves are electrically operable every 92 days in accordance with STP V-3F2. Id. at 3. Yet, prior to this event, the STP for this valve did not require manual cycling of the valve to verify manual operability of the handwheel. Id. at 6. The last documentation of the manual operability of SW-1-FCV-496 was on 6/11/82. Id. at 4.

**715- Finding: PG&E did not render SW-1-FCV-496 manually operable in a timely or effective manner because spare parts were not available. Moreover, PG&E assigned low priority to this equipment because its safety role was not recognized.**

716- PG&E itself determined that "the frequency of preventative maintenance is too low to prevent corrosion of the handwheel in these environmental conditions," i.e. the harsh conditions of the intake structure. Id. at 6.

717- PG&E has admitted that "corrosion of the handwheel was to be expected in the harsh environment which it is located, but that the untimeliness of corrective maintenance needed to be examined." Id. at 16.

718- On 6/29/90, PG&E discovered that the SW-1-FCV-496 was not manually operable. It wasn't until 9/14/90 that personnel first attempted to free the handwheel. PG&E maintenance technicians attempted to disassemble the valve and were not able to do so. No further efforts were attempted because sufficient parts were not available for an overhaul. Id. at 2.

719- On 1/16/91, the NRC resident noticed an old AR tag on FCV-495. This led to further efforts to free the handwheel on FCV-496. "Copious quantities of penetrating oil, picks, emery paper and hacksaw blades were all used in a cautious and methodical effort to free the handwheel... spare parts were still not available." Around mid-day on 1/17/91, the job was finally accomplished. Id. at 3.

720- The Licensing Board determines that PG&E was slow to respond to the repair of SW-1-FCV-496 because spare parts were not available from (at least) 6/29/90 until 1/16/91. We find it unacceptable that after six and one half months PG&E still had not acquired replacement parts. The Board finds its failure to do so demonstrative of a deficient maintenance program at DCNPP as well as a deficient supplier certification program.

721- Additionally, PG&E was slow to respond to the repair of SW-1-FCV-496 because sufficient priority was not assigned to the manual operation of this valve. Id. at 2. The valve is designated as Class I (safety related), yet the operator that operates the valve has been designated as Class II (non-safety related). Tr. at 1715. The TRG found that "no method exists to identify Class II equipment which requires higher priority maintenance or to convey the importance of the equipment to craftsmen." MFP Exhibit 168 at 16. PG&E has made some response to this problem, but we believe it is insufficient. PG&E has committed to performing a review "to identify all power operated valves that require manual operation of the valve to fulfill a safety function." Id. at 9. However, as articulated by the TRG, PG&E's problem with maintaining Class II equipment with high priority maintenance requirements is not confined to power operated valves. PG&E's maintenance program remains deficient because it has not addressed this broader issue.

722- In conclusion, the Licensing Board finds PG&E's maintenance and surveillance program to be profoundly deficient in its failure to acknowledge the importance of the manual operation of these valves, to monitor the condition and manual operability of the valves, to obtain replacement parts, or to act in a timely and effective manner when a problem was realized. See Untimely Response to Maintenance Problems in the General Findings.

TESTCOCK VALVE ON DIESEL GENERATOR

Exhibit 172: NCR DCO-91-MM-N049 (10/2/91)

Transcript pages: 1745-1753

723- On 6/3/91, PG&E performed maintenance on Diesel Generator (DG) 1-3. In addition to other work, testcock valve at cylinder 8R was replaced. During post-maintenance testing, leakage was noticed at the threads of the testcock at this valve. Mechanical Maintenance inspected and replaced the copper washers on testcock 8R.

724- When it came time to perform the second leak check/tightness check on testcock 8R, testcock 2R was inadvertently checked. As a result, this testcock valve broke off at the face of the diesel head. NCR DCO-91-MM-N049 (10/2/91), MFP Exhibit 172 at 2,3.

725- PG&E determined that the failure of testcock valve 2R was due to mechanical fatigue cracking. The most probable cause of this high cycle fatigue is loosening of testcock 2R in service resulting in a "looser" fit and allowing the high cycle vibration to occur at the testcock connection. Id. at 5. Looseness of the connection may have been due to the lack of a copper washer. Vendor literature at the time did not require the use of a copper washer. Id. at 6.

**726- Finding: The degradation of testcock valve 2R was identified due to an error in the post-maintenance testing procedure.**

727- PG&E emphasizes that the degraded testcock valve was discovered during a maintenance process and subsequent post-maintenance test. Tr. at 1747. Yet, the Licensing Board cl· ifies that this discovery was made only because the maintenance personnel made a mistake; he tightened the incorrect testcock valve and it broke. See Specific Findings regarding Motor Pinion Keys in Limitorque Motor Operators. It addresses another incident in which a surveillance test was performed incorrectly and, as a result, a degraded component was discovered. Clearly, PG&E's maintenance and surveillance program was not intended to work in this manner. The Board finds that these two incidents taken together reflect a weakness in PG&E's maintenance and surveillance program at DCNPP.

MAIN FEEDWATER CHECK VALVE

MFP Exhibit 190: NCR DC1-91-TN-N002 (2/18/91)
MFP Exhibit 191: NCR DC1-90-OP-N083 (2/8/91)
MFP Exhibit 192: LER 1-91-015-01 (1/25/91)
MFP Exhibit 193: NRC "Review of LER 1-90-015-00 (1/18/91)

Transcript pages: 1771-1794, 2256-2260

728- Since 1989, DCNPP has experienced a series of incidents involving the malfunction of Main Feedwater Check Valve FW-1-531. There are two sets of incidents, the first set involving multiple reactor trips, and the second involving ESF actuation.

Reactor Trips

729- Following multiple reactor trips, Main Feedwater check valve FW-1-531 failed to fully seat as expected and PG&E identified the potential for loss of auxiliary feedwater flow through this path. NCR DC1-91-TN-N002 (2/18/91), MFP Exhibit 190 at 1.

730- On 11/9/89, plant operators noted that Steam Generator (SG) 1-3, Main Feedwater check valve, FW-1-531, was leaking. It was repaired during 1R3. Id. at 2. Feedwater check valve FW-1-531 is a safety category I valve installed to protect the SG and reactor coolant system (RCS) from excessive cooldown due to blowdown following a postulated line rupture in the safety category II portion of a feedwater line. Id. at 6.

731- Following the reactor trip of 2/20/90, PG&E again found FW-1-531 leaking. The check valve did not fully close following the reactor trip and also unseated during the reactor startup of 2/21/90.

> The need for corrective maintenance action was considered by plant management and the determination was made that plant operators were capable of operating the feedwater system with the identified backleakage due to training, procedural caution concerning feedwater startup and procedural requirement for additional operators to be present during startup. Also, an information tag was placed on FCV-440 control switch indicating that FCV-440 may need to be closed following a reactor trip in order for full AFW flow to go to SG 1-3, due to backleakage. Id. at 2.

732- On 6/14/90, another reactor trip occurred. On 6/17/90, a main feedwater system water hammer occurred. "The need to perform further maintenance or investigation regarding

FW-1-531 leakage was considered by management... and the determination was made not to require further maintenance actions during the forced outage." Id. at 3.

733- On 12/6/90, plant operators noted that they had experienced leakage again after another reactor trip, and FCV-440 had to be closed to stop the backleakage. Id.

734- PG&E determined that the root cause of the leaking valve was the valve design that demands additional caution during final assembly after repairs and/or inspection of the valve seat or disk. This sensitivity was not expected by knowledgeable craft personnel and was not identified in the vendor literature. PG&E also identified contributory causes which included: (1) failure of the vendor to provide additional valve assembly information and (2) plant management, maintenance personnel and operations personnel were aware of the degraded condition of the check valve for approximately one year. The plant had been shut down three times following reactor trips, twice after a maintenance solution had been determined during 2R3. Id. at 5,6.

**735- Finding: Inadequate maintenance was performed on feedwater check valve FW-1-531 during 1R3.**

736- As PG&E itself conceded, "installation of the replacement disc during 1R3 was inadequate due to lack of available vendor information. The assembly requirements of this valve following maintenance were reviewed in detail and determined to be beyond the 'skill of the craft.'" Id. at 5.

**738- Finding: PG&E failed to respond to the degraded condition of check valve FW-1-531 in a timely fashion.**

739- Plant management, maintenance personnel and operations personnel were aware of the degraded condition of the check valve for approximately one year. The plant had been shut down three times following reactor trips, twice after a maintenance solution had been determined during 2R3. Id. at 5,6. Yet, this valve was not repaired.

ESF Actuation

740- On 12/8/90, an Engineered Safety Features (ESF) actuation occurred due to SG 1-3 high-high level which resulted in a feedwater isolation, P-14, closure of the main feedwater, feedwater bypass and feedwater isolation valves. Backleakage through FW-1-531 was initially believed to have contributed to the P-14 actuation. PG&E later noted that, although valve FW-1-531 did not directly contribute to the ESF actuation, it did represent a "degraded condition of the auxiliary feedwater system capability to deliver full flow to the steam generator." Id. at 3.

741- The root cause of the ESF was determined to be due to

> leakage through feedwater regulating valve FW-1-FCV-530 and feedwater regulating bypass valve FW-1-FCV-1530. FW-1-FCV-530 was stroke tested during a Unit 1 forced outage which began on December 23, 1990, and it was determined that leakage through this valve was due to valve position controller drift. FW-1-FCV-1530 was disassembled and inspected during the same forced outage. Leakage through this valve was also due to valve position controller drift. NCR DC1-90-OP-N083 (2/8/91), MFP Exhibit 191 at 5.

742- On 12/21/90, as a result of further investigation regarding feedwater system leakage, PG&E determined that feedwater recirculation control valve FW-1-FCV-420 was leaking to the condenser. Leakage past the valve contributed to the ESF in that it provided a leak path to the condenser. Id.

**743- Finding: Poor communication was a factor in this event.**

744- PG&E addressed the December 1990 ESF event in LER 1-90-015-00. The NRC responded with a review of this report stating:

> Our understanding of the event indicates that the valves discussed in the LER (main feedwater check valve FW 531, main feedwater regulating valve FW 530, and the main feedwater regulating bypass valve FW 1530) were observed to be leaking and causing level control difficulties during unit restart attempts or reactor trips in December 1989, February 20, 1990, February 22, 1990, and also on June 14 and June 19, 1990. Therefore it would appear the operators should not have been surprised by the leaking valves and either should have been pre-warned and provided with a strategy for dealing with the leaking valves, or the valves should have been fixed at one of the earlier opportunities. Operator statements after the December 8, 1990, event indicate that they were not aware of the valve conditions. It appears that the lack of operator knowledge should be considered as a root cause and appropriate corrective action considered. NRC "Review of LER 1-90-015-00 (1/18/91), MFP Exhibit 193 at 1.

745- The Board is mystified as to why information regarding these leaks apparently was not passed on to the operators. It seems there was no mechanism for assuring that the information would be given to the appropriate personnel. We consider this to be part of the overall communication problem that we have noted in the general findings.

**746- Finding: PG&E failed to implement timely investigative and corrective action.**

747- The NRC noted that

> the fact that the valves leaked should not have caused a rapid level drop in steam generator 1-3 unless the water had a location to which to flow. Your LER does not describe the flow path. It is our understanding that another valve, FCV420, the feedwater recirculation valve to the main condenser, was found to have substantial seat leakage on December 21, 1990, during an operations walkdown done in response to inquiries as to where the feedwater was flowing. Therefore it appears that lack of timely investigative and corrective action after the previously observed level control events outlined above, may have been a contributing root cause and may indicate other appropriate corrective actions are required. MFP Exhibit 193 at 1.

748- PG&E thus revised its original LER and submitted LER 1-90-015-01 (1/25/91), MFP Exhibit 192. It included as a contributing cause "plant management's failure... to provide direction for either a timely repair of the feedwater valves or an adequate strategy for operators to enable them to startup the unit with leaking feedwater valves." MFP Exhibit 192 at 1.

749- In conclusion, the Board observes that the leaking feedwater check valve FW-1-531 was first identified early in November of 1989. An unsuccessful attempt was made at repair during 1R3. PG&E then made a conscious decision to operate with the check valve leakage because it "would not pose any burden on the operators in operating the plant..." Tr. at 1779,1780. It intentionally bypassed opportunities to make repairs during several forced outages due to reactor trips. Other issues that came into play involved sensitive valve design and inadequate vendor information. This situation was further complicated by the occurrence of the ESF in December of 1990 and the appearance of other leaking valves - a feedwater regulating valve, a feedwater regulating bypass valve and a feedwater recirculating valve.

750- The Licensing Board finds that this series of events contained a multitude of questionable actions and assumptions that led to numerous reactor trips, an ESF and a degraded feedwater system. As a result, the main feedwater check valves remained in a faulty condition for a matter of years. The Board finds these events to constitute strong evidence that the maintenance and surveillance organization at DCNPP lacks a sufficiently effective and comprehensive program to provide a reasonable assurance of safe operation at DCNPP.

<u>ASW PUMP VAULT DRAIN CHECK VALVES</u>

MFP Exhibit 196: NCR DCO-91-MM-N067 D6 (1/15/91)

Transcript pages: 1794-1806

751- There are two auxiliary salt water (ASW) pumps per unit, and each of the pump vaults has a drain and a check valve to prevent reverse flow. Tr. at 1797,1798. On 8/8/91, mechanical maintenance removed the ASW pump 1-1 and 1-2 vault drain check valves for routine periodic inspection and refurbishment. No clearance was requested or approved for the work. The check valves were found to be degraded and both check valves were physically removed from the system. NCR DCO-91-MM-N067 D6 (1/15/91), MFP Exhibit 196 at 2.

752- PG&E discovered that the ball float check valves in these drain lines have had their internals removed since 1989. Both check valves were found partially stuck open due to trash, eg., tie wraps, cigarette butts, etc. Id.

753- PG&E determined that this event was not a non-conformance based on the NECS-Engineering classification of the ASW pump vault drain check valves as Class II and the Operations determination the ASW pumps were operable during the period when the ASW pump vault drain check valves were removed. Id. at 12.

754- PG&E determined that no root cause needed to be identified because the event was not a non-conformance. However, PG&E listed a number of contributory causes to the event which showed a breakdown in maintenance procedures:

> 1. The WO [work order] prerequisites included a verification of clearance points but no clearance was requested.
> 2. The WO prerequisites incorrectly specified "MARK 'N/A' IN 'SFM AUTH"..."
> 3. No tailboard was held with the System Engineer contrary to prerequisite C of the work order.
> 4. The Maintenance Engineer was contacted too late to permit evaluation of the "as-found" condition of the valves.
> 5. New gaskets were not installed during reinstallation (none were initially found in the valve).
> 6. The Journeyman did not stop the job to correct the WO anomalies.
> 7. There are no P&IDs showing these valves.
> 8. It was not documented that these valves were found stuck partially open due to debris.
> 9. The Foreman did not visit the job site during the job.

10. The Foreman and Journeyman were not knowledgeable regarding the technical configuration management decision process.
11. Drawings were not updated in a timely manner when the internals for the ball float check valves were removed in 1989.

Id. at 5,6.

755- The TRG also found that "the WO specifies A-107 bolting for the check valves but the 'as-found/as-left bolting was brass. No torque wrench was used on the bolting, the Journeyman used independent judgment." Id. at 11.

**756- Finding: This event shows multiple personnel errors occurring in the same activity, which indicates a programmatic deficiency in PG&E's maintenance and surveillance program.**

757- As noted by the TRG, a "barrier analysis" of this event shows that "four distinct barriers that should have prevented the event were broken through." Id. at 12. Although this event was ultimately deemed not to constitute a non-conformance, it nevertheless revealed a striking number of personnel errors, all related to the same task. As with the events surrounding the installation of the wrong motor on a motor operated valve, we find that the committing of such large number of personnel errors with respect to one maintenance activities raises the alarm that there is a serious problem with PG&E's maintenance program. Therefore, we cannot find it to be adequate. See Specific Findings for details regarding Wrong Size Motor Installed and General Findings for discussion regarding Personnel Errors.

SI-1-8805A FAILED TO CYCLE ON ACTUATION SIGNAL

MFP Exhibit 210: NCR DC1-90-EM-N042 (6/27/90)

Transcript pages: 1808-1818

758- In 12/82, PG&E overhauled the motor operator for valve SI-1-8805A as part of the preventive maintenance program for Limitorque Motor Operators. NCR DC1-90-EM-N042 (6/27/90), MFP Exhibit 210. This safety-related valve is one of two parallel valves which open on an SI signal. MFP Exhibit 210 at 5.

759- On 5/25/90, the valve failed when operators tried to test it during operation. The motor operator was overhauled and the declutch fork was found installed upside down. With the declutch mechanism installed upside down, it only partially engaged. The partial engagement caused excessive stress on the load bearing surfaces and eventually caused a failure. It took eight years for the motor operator to fail because of "aging and stressing of components." Id. at 3.

760- Routine surveillance, which does not involve disassembly of the valve operator, did not detect the improper installation of the clutch. Tr. at 1810. PG&E determined that the root cause of the incorrect installation of the declutch fork was due to the facts that: (a) the procedures used at the time of the valve overhaul in 1982 did not include adequate instructions for the installation of the declutch fork. Id. at 4. (b) a training program for the overhauling of Limitorque motor operators did not exist in 1982. Id. at 5. See Tr. at 1810.

**761- Finding: PG&E's safety analysis of this event is inadequate and reflects deficiencies in PG&E's maintenance and surveillance program.**

762- In its safety analysis of this event, PG&E gives two reasons why it attributes low safety significance to this valve failure. The Board finds that both reasons are inadequate, and moreover that they indicate a poor understanding of and/or attitude toward the fundamental safety principles governing the maintenance of the plant. First, PG&E argues that the other parallel valve, SI-8805B, was available and could have performed the safety function. MFP Exhibit 210 at 5. However, under the principles enunciated in the General Design Criteria in 10 C.F.R. Part 50, Appendix A, the DCNPP must be designed and maintained not just to maintain one safety system, but two redundant and independent safety systems. In fact, it must be assumed that during an accident, a single random failure may knock out one of those safety systems, leaving the plant to rely completely on the other safety system. Poor maintenance practices resulting in disabling of a safety component or system cannot qualify as a single random failure. For purposes of a safety analysis, there would have been no SI valve available during an accident. PG&E does not analyze the safety implications of such a situation, but they are probably significant. As with many of the other safety analyses that we have reviewed in the course of this proceeding, PG&E's failure to take the principle of redundancy into account is a serious concern, and represents a programmatic deficiency in its maintenance program.

763- PG&E's second reason for asserting that this valve failure had low safety significance was that it "fully opened on an actuation signal." Id. at 5. We believe that PG&E is taking improper credit for pure luck. We also note that a safety problem was created in that, after attempting to open, then close, then open the valve, the control room operator apparently could not tell whether the valve was open or closed: the operator "was under the impression that the breaker had failed to close, and proceeded to cycle the breaker several times." Id. at 5. PG&E does not evaluate the safety significance of the operator's uncertainty regarding the valve position had the failure occurred during an accident.

**764- Finding: The deficient installation went undetected until the component failed, thus showing an inadequacy in PG&E's maintenance and surveillance program.**

765- The Licensing Board finds that, in this instance, deficient maintenance went undetected for many years - until the accumulated stresses caused by the improper maintenance finally caused it to fail. The Board concludes that this event indicates an inadequacy in the maintenance and surveillance program at DCNPP.

FIRE IN ELECTRICAL PANEL

MFP Exhibit 216: NCR DCO-90-SE-N080 (1/28/92)

Transcript pages: 1818-1826

766- On 11/19/90, smoke was detected coming from a 480 VAC electrical panel in the security diesel area. Equipment failure was the cause of the fire. PG&E found that "although the feeder breaker was damaged to the extent that a detailed cause of the failure was impossible to make," the "most probable cause" was "an inadequate compression wiring termination installation which resulted in increased electrical resistance across the termination resulting in heating until some semi-combustible materials in the area began to smolder." NCR DCO-90-SE-N080 (1/28/92), MFP Exhibit 216 at 2,3. PG&E also found that a contributory cause was that "compression electrical terminations are dependent on the skill of the installer for acceptable results." Id. at 6.

767- **Finding: PG&E considered replacing the faulty connectors years ago, but did not do so for financial reasons - thus undermining the safety of the plant.**

768- PG&E claims that there is nothing inadequate about the compression connections. Tr. at 1823. However, we find that the very occurrence of the fire, which PG&E itself believes was probably caused by the connections, undermines the validity of that assertion. It must also be noted that during the 1970s, when PG&E decided to change compression electrical terminations in Class I, high voltage equipment, to crimped-lug style terminations, it made a "conscious, <u>economic</u> decision" at that time to **not** change them in Class II equipment. MFP Exhibit 216 at 5 (emphasis added). The fire in the VAC electrical panel would probably have been avoided had PG&E upgraded the connectors. Thus, financial considerations undermined the adequacy of the maintenance program at DCNPP.

<u>CHEMICAL AND VOLUME CONTROL SYSTEM DIAPHRAGM LEAKAGE</u>

PG&E Exhibit 28: LER 1-92-009-01 (1/11/93)
PG&E Exhibit 29: LER 2-91-009-01 (4/24/92)

Transcript pages: 1826-1839
PG&E Testimony: 100-102

769- During normal plant operation, the primary function of the Chemical and Volume Control System (CVCS) is to maintain reactor coolant system inventory. During a postulated accident, portions of the system are used to recirculate and supply water to mitigate the accident. PG&E Ts. at 100,101.

<u>1991 CVCS Leakage</u>

770- During the performance of a hydrostatic test on 9/26/91, diaphragm valves CVCS-2-548 and CVCS-2-8471 were leaking. The identified leakage was coming from between the valve body and bonnet to both valves. Leakage from both valves was estimated to be approximately 1.3 gpm. LER 2-91-009-01 (4/24/92), PG&E Exhibit 29 at 1.

771- These valves are located in the boric acid blender; its ventilation exhausts to the plant vent without passing through charcoal filters. Therefore, any radioactive material that may be released as a result of leakage from these valves would be released to the plant vent filtered only by high efficiency particulate air filters (HEPA). PG&E evaluated the situation and determined that the leakage could have resulted in the control room and exclusion area boundary 10 CFR 100 dose limits being exceeded during the recirculation phase of recovery from a design basis LOCA. Id. at 2.

772- The LER for this event noted a previous LER on a similar event: LER 1-90-010-00 addressed the leakage of post-LOCA coolant into the charging pump rooms. The leakage would have resulted in exceeding the control room design basis dose limit. The cause of the event was determined to be high cycle fatigue crack. Id. at 5.

**773- Finding: Leakages from CVCS-2-8471 and CVCS-2-548 were due to errors made in the preventive maintenance program.**

774- PG&E attributed the root cause of body-to-bonnet leakage in CVCS-2-8471 to personnel error in that the valve was not included in the plant preventive maintenance program.

Since the valve was not included in this program, the diaphragm's service life was exceeded. Id. at 4.

775- CVCS-2-548 was included in the preventive maintenance program. And although the specific root cause of the body-to-bonnet leakage could not be determined, it was noted that vendor recommendations on retorquing bonnet bolts were not included in the preventive maintenance program. This may have been a factor in the root cause. Id.

1992 CVCS Leakage

776- On 6/22/92, diaphragm valve CVCS-1-547, which regulates the emergency borate flow to the volume control tank outlet isolation in the CVCS, was found to be leaking approximately 0.5 gpm to the auxiliary building atmosphere. LER 1-92-009-01 (1/11/93), MFP Exhibit 28. CVCS-1-547 is located in the boric acid blender room. Again, the room ventilation exhausts to the plant vent without passing through charcoal filters. Any radioactive material that may be released as a result of leakage in this area, then, would be filtered only by HEPA. PG&E determined on 6/26/92 that this leakage could have caused 10 C.F.R. 100 and GDC 19 dose limits to be exceeded during a design basis LOCA. PG&E Exhibit 28 at 2.

778- DCNPP technical specifications requires the installation of electric heat trace circuitry to maintain the temperature of lines above 145 degrees F. Id. at 3. Although heat tracing is not installed on the bonnet of CVCS-1-547, the valve had insulation installed. Id. at 5. The heat trace controller (thermostat) for this segment of system piping is not at CVCS-1-547. The physical arrangement of the piping at CVCS-1-547 resulted in heat accumulation at the valve, as evidenced by measured valve body temperature. Investigation determined that the heat trace controller for CVCS-1-547 was not turning off. Id.

779- Investigation also determined that the bonnet temperature of CVCS-1-547 was approximately 304 degrees F. Information from the valve vendor (ITT) indicated that the qualified operating limits for the valve diaphragm are 100 psig at 300 degrees F, 175 psig at 250 degrees F and 235 psig at 200 degrees F. Therefore, the as-found condition was in excess of the vendor-recommended limits. Additionally, the valve bonnet retaining nuts were only "finger-tight." Id. at 3.

780- PG&E found that the cause of the leakage was "thermally-induced premature degradation of the valve diaphragm caused by a malfunctioning heat trace controller, resulting in distortion of the diaphragm at the body-to-bonnet joint and breaching of the system pressure boundary." Id. at 1.

781- PG&E claims that the leakage in both this and the 1991 events had no safety significance because there was no actual safety consequences. Yet, PG&E admits that the situation had the potential to be significant. Tr. at 1828,1829.

782- **Finding: Multiple deficiencies enabled this event to occur.**

783- Multiple deficiencies led to the leakage of the CVCS system: the retaining nuts were loose, there was a component failure, and the vendor-recommended operating temperature was exceeded.

784- In a two-year period, DCNPP has experienced CVCS system leakage in both units. This leakage could have impacted public health and safety had the r leases been higher. The Board concludes that PG&E's maintenance program was inadequate in excluding one of the CVCS valves in its preventive maintenance program. Moreover, to the extent that these valves were included in the preventive maintenance program, the program was plagued with an array of problems: poor procedures for maintenance, failure to detect faulty heat tracers, failure to monitor the temperature to which the valves were installed, improper torquing of valve bonnet retaining nuts. The Board finds that this broad array of deficiencies implicates the overall adequacy of PG&E's maintenance and surveillance program.

**TABLE A**

These tables are based on PG&E's data sheets for Teletemp Stickers which were provided to SLOMFP. Given the cumbersome procedure and data forms, the accuracy of this information cannot be guaranteed.

Teletemp Sticker Temperature Readings, Unit 1

| item: | **1R2** (6/88) | |
|---|---|---|
| FCV-37 | 100,120 | |
| FCV-38 | >200,>200 | reached maximum temp. recordable; 2 stickers & should be 4 |
| FCV-95 | 140,140 | |
| FCV-438 | 120,"?" | sticker not legible |
| FCV-439 | 100,100 | |
| FCV-440 | 140,140 | 2 stickers; should be 4 |
| FCV-441 | 140,140 | 2 stickers; should be 4 |
| FCV-658 | 100,100 | |
| FCV-659 | 100, ? | only 1 sticker; should be 2 |
| FCV-749 | 100,100 | |
| FCV-750 | 120,120 | |
| 8000A | 140,140 | |
| 8000B | 160,160 | |
| 8000C | 140,140 | |
| 8078A | 140, ? | only 1 sticker; should be 2 |
| 8078B | 140, ? | only 1 sticker; should be 2 |
| 8078C | 160, ? | only 1 sticker; should be 2 |
| 8078D | 160, ? | only 1 sticker; should be 2 |
| 8112 | 120,120 | |
| 8701 | 100,120 | |
| 8702 | 140,140 | |
| 8703 | 100,100 | |
| RE-73 | | no data sheet found |
| RE-74 | | no data sheet found |
| general area(K6481) | 180 | |
| general area(KT251)115' | 120,100 | |
| general area(KT251)133' | 160,140 | |
| general area(ceiling) | | no data sheet found |
| general area(K6442) | | no data sheet found |
| general area(K880) | | no data sheet found |
| general area(K1768) | 140 | |
| general area(cable tray) | 120,120,120,120 | |
| conduit KT319 | | no data sheet found |
| general area(near FCV-38) | | no data sheet found |
| conduit K5787 | | no data sheet found |
| conduit above and behind FCV-38 | 160 | |
| conduit KR027 | | no data sheet found |
| conduit KR029 | | no data sheet found |
| conduit K6467 | | no data sheet found |

**TABLE A**

This table is based on PG&E's data sheets for Teletemp Stickers which were provided to SLOMFP. Given the cumbersome procedure and data forms, the accuracy of this information cannot be guaranteed.

Teletemp Sticker Temperature Readings, Unit 1

| item: | **1R3** (11/89) | |
|---|---|---|
| FCV-37 | <100,<100 | |
| FCV-38 | 200,200 | reached sticker capacity; only 2 stickers & should be 4 |
| FCV-95 | 120,140 | |
| FCV-438 | 120,<100 | |
| FCV-439 | 100,<100 | |
| FCV-440 | 120,120 | only 2 stickers; should be 4 |
| FCV-441 | 140,140 | only 2 stickers; should be 4 |
| FCV-658 | <100,<100 | |
| FCV-659 | <100,<100 | |
| FCV-749 | <100,<100 | |
| FCV-750 | <100,<100 | |
| 8000A | 160,160 | |
| 8000B | 140,140 | |
| 8000C | 140, ? | only 1 sticker; should be 2 |
| 8078A | 140,140 | |
| 8078B | 140,140 | |
| 8078C | 160,160 | |
| 8078D | 160,160 | |
| 8112 | 120,120 | |
| 8701 | 120,120 | |
| 8702 | 140,160 | |
| 8703 | <100,<100 | |
| RE-73/RE-74 | 120,120 | |
| general area(K6481) | 180 | |
| general area(KT251)115' | | no data sheet found |
| general area(KT251)133' | | no data sheet found |
| general area(ceiling) | | no data sheet found |
| general area(K6442) | | no data sheet found |
| general area(K880) | | no data sheet found |
| general area(K1768) | 140 | |
| general area(cable tray) | 120,120 | only 2 stickers; should be 4 |
| conduit KT319 | | no data sheet found |
| general area(near FCV-38) | 160 | |
| conduit K5787 | 160, ? | only 1 sticker; should be 2 |
| conduit above and behind FCV-38 | | no data sheet found |
| conduit KR027 | 140 | |
| conduit KR029 | 140 | |
| conduit K6467 | | no data sheet found |

**TABLE A**

This table is based on PG&E's data sheets for Teletemp Stickers which were provided to SLOMFP. Given the cumbersome procedure and data forms, the accuracy of this information cannot be guaranteed.

Teletemp Sticker Temperature Readings, Unit 1

| item: | **1R4** (readings from 8/90-1/91) | |
|---|---|---|
| FCV-37 | --- | no stickers or comments on data sheet |
| FCV-38 | 190/200,190/200 | |
| FCV-95 | 120,140 | |
| FCV-438 | 110 | 4 stickers found; 3 "no indication" |
| FCV-439 | --- | 4 stickers found; "no temp change" |
| FCV-440 | 140,140 | only 2 stickers; should be 4 |
| FCV-441 | 140,140 | only 2 stickers; should be 4 |
| FCV-658 | <100,<100 | "old stickers not found" (how was "<100" determined? |
| FCV-659 | <100,<100 | |
| FCV-749 | <100, ? | data not recorded for 2nd sticker |
| FCV-750 | <100,<100 | |
| 8000A | 120,120 | "valve also had high range on it but it was not chaned and stickers were not in package. |
| 8000B | 140, ? | "procedure should explain how to read stickers" |
| 8000C | 120,120 | "valve also had high range but was not changed. Color had not changed and was not in package. |
| 8078 | | no data sheet found |
| 8078B | | no data sheet found |
| 8078C | | no data sheet found |
| 8078D | | no data sheet found |
| 8112 | 120,120 | |
| 8701 | <140,120,<140,120 | |
| 8702 | 140,160,160,140 | |
| 8703 | <140,110 | |
| RE-73 | 140 | |
| RE-74 | 140 | |
| general area(K6481) | 180 | |
| general area(KT251)115' | | no data sheet found |
| general area(KT251)133' | | no data sheet found |
| general area(ceiling) | 180,180 | |
| general area(K6442) | 120 | |
| general area(K880) | 160 | |
| general area(K1768) | 140 | |
| general area(cable tray) | 120, ? | only 1 sticker; should be 4 |
| conduit KT319 | 160,140,120 | 4th sticker not recordable |
| general area(near FCV-38) | | no data sheet found |
| conduit K5787 | | no data sheet found |
| conduit above and behind FCV-38 | | no data sheet found |
| conduit KR027 | | no data sheet found |
| conduit KR029 | | no data sheet found |
| conduit K6467 | 160 | |

**TABLE A**

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Teletemp Sticker Temperature Readings, Unit 1

| item: | **1R5** (10/92) | |
|---|---|---|
| FCV-37 | 110,110 | |
| FCV-38 | 220,220 | note high temp. |
| FCV-95 | 160,170 | |
| FCV-438 | 110,110 | |
| FCV-439 | 100,100 | |
| FCV-440 | 140,140 | only 2 stickers; should be 4 |
| FCV-441 | 120,140 | only 2 stickers; should be 4 |
| FCV-658 | >100,>100 | |
| FCV-659 | >100,>100 | |
| FCV-749 | 110,110 | |
| FCV-750 | ? ? | "no temp stickers found" |
| 8000A | 170, ? | only 1 sticker; should be 2 |
| 8000B | 170,170 | |
| 8000C | 170,170 | |
| 8078A | | no data sheet found |
| 8078B | | no data sheet found |
| 8078C | | no data sheet found |
| 8078D | | no data sheet found |
| 8112 | 130,130 | |
| 8701 | 100,100 | |
| 8702 | 140,140 | |
| 8703 | 100,100 | |
| RE-73 | 120 | |
| RE-74 | 120 | |
| general area(K6481) | 170 | |
| general area(KT251)115' | | no data sheet found |
| general area(KT251)133' | | no data sheet found |
| general area(ceiling) | 170,220 | note high temp. |
| general area(K6442) | 100 | |
| general area(K880) | 160,140 | |
| general area(K1768) | 160 | only supposed to be 1 sticker, but comment is "couldn't find" 2nd sticker |
| general area(cable tray) | | no data sheet found; should be 4 stickers |
| conduit KT319 | 160,160,170 | |
| general area(near FCV-38) | | no data sheet found |
| conduit K5787 | | no data sheet found |
| conduit above and behind FCV-38 | | no data sheet found |
| conduit KR027 | | no data sheet found |
| conduit KR029 | | no data sheet found |
| conduit K6467 | 180,180 | |

**TABLE B**

This table is based on PG&E's data sheets for Teletemp Stickers which were provided to SLOMFP. Given the cumbersome procedure and data forms, the accuracy of this information cannot be guaranteed.

Teletemp Sticker Temperature Readings, Unit 2

| item: | **2R2** (11/88) | |
|---|---|---|
| FCV-37 | --- | "no old stickers found" |
| FCV-38 | 160,160 | only 2 stickers; should be 4 |
| FCV-95 | --- | "no old stickers found" |
| FCV-438 | --- | "no old stickers found" |
| FCV-439 | --- | "no old stickers found" |
| FCV-440 | 120,120 | only 2 stickers; should be 4 |
| FCV-441 | --- | "no old stickers found; should be 4 |
| FCV-658 | 100,100 | |
| FCV-659 | 100,100 | |
| FCV-749 | 100,100 | |
| FCV-750 | 100,100 | |
| 8000A | 180,180 | note high temp. |
| 8000B | 180,180 | note high temp. |
| 8000C | 180,180 | note high temp. |
| 8078A | 160,140 | |
| 8078B | 140,140 | |
| 8078C | 160,160 | |
| 8078D | 160,160 | |
| 8112 | --- | "no old stickers found" |
| 8701 | 100,100 | |
| 8702 | 120,120 | |
| 8703 | 100,100 | |
| RE-73 | | no data sheet found |
| RE-74 | | no data sheet found |
| general area(K6126) | | no data sheets for these areas |
| GW/117 | | |
| GW/126 | | |
| GW/133 | | |
| GW/conduit/hanger | | |
| general area(ceiling) | | no data sheet found |
| general area(K6442) | | no data sheet found |
| general area(K1768) | | no data sheet found |
| general area(cable tray) | --- | "no old stickers found" - should be 4 stickers |
| general area(near FCV-38) | | |
| GW/115 | 140, 120 | "found only 2 stickers; affixed 3rd sticker in general area as per M. Smiths instructions." |

**TABLE B**

This table is based on PG&E's data sheets for Teletemp Stickers which were provided to SLOMFP. Given the cumbersome procedure and data forms, the accuracy of this information cannot be guaranteed.

Teletemp Sticker Temperature Readings, Unit 2

| item: | **2R3** (3/90) | |
|---|---|---|
| FCV-37 | <100,120 | |
| FCV-38 | 180,180 | note high temp. and only 2 stickers; should have 4 |
| FCV-95 | 120,120 | |
| FCV-438 | 120,120 | |
| FCV-439 | 120,120 | |
| FCV-440 | 140,140 | only 2 stickers; should have 4 |
| FCV-441 | 140,140 | only 2 stickers; should have 4 |
| FCV-658 | --- | "no temp recordable" |
| FCV-659 | --- | "no temp recordable" |
| FCV-749 | --- | "no temp recordable" |
| FCV-750 | | no data sheet found |
| 8000A | 160,160 | |
| 8000B | 180, ? | "sticker #2 not present"-note high temp. |
| 8000C | 160, ? | "sticker #2 not present" |
| 8078A | | no data sheet found |
| 8078B | | no data sheet found |
| 8078C | | no data sheet found |
| 8078D | | no data sheet found |
| 8112 | 120, -- | "sticker #2 not legible" |
| 8701 | --- | "I cannot record a temperature per these stickers." |
| 8702 | 120,120 | |
| 8703 | --- | "I cannot record a correct temperature from these stickers." |
| RE-73 | --- | none found |
| RE-74 | --- | none found |
| general area(K6481) | 160 | |
| general area(K6126) | | |
| GW/117 | | no data |
| GW/126 | | no data |
| GW/133 | | no data |
| GW/135 | | no data |
| general area(ceiling) | 160,160 | |
| general area(K6442) | | no data sheet found |
| general area(K1768) | --- | "new equipment" |
| general area(cable tray) | | no data sheet found; should be 4 stickers |
| general area(K912) | --- | no data |

**TABLE B**

This table is based on PG&E's data sheets for Teletemp Stickers which were provided to SLOMFP. Given the cumbersome procedure and data forms, the accuracy of this information cannot be guaranteed.

Teletemp Sticker Temperature Readings, Unit 2

| item: | **2R4** (9/91) | |
|---|---|---|
| FCV-37 | 120,120 | |
| FCV-38 | 180,180,220,190 | note high temps. |
| FCV-95 | --- | "no stickers found" |
| FCV-438 | 120,120 | |
| FCV-439 | 120,120 | |
| FCV-440 | 120,120,160,160 | |
| FCV-441 | 160,120,170,120 | |
| FCV-658 | 110,110 | |
| FCV-659 | 120,170 | |
| FCV-749 | 110,110 | |
| FCV-750 | 120,120 | |
| 8000A | "77,77" | used centigrade; should be 170 |
| 8000B | 160,>190 | reached sticker capacity |
| 8000C | >190,>200 | both reached sticker capacity |
| 8078A | --- | new valves (A-D) |
| 8078B | --- | |
| 8078C | --- | |
| 8078D | --- | |
| 8112 | 120,120 | |
| 8701 | 110,110 | |
| 8702 | 120,120 | |
| 8703 | 110,110 | |
| RE-73 | 120,120 | |
| RE-74 | 120,120 | |
| general area(K6126) | | |
| GW/117 | 160 | |
| GW/126 | 160 | |
| GW/133 | 160 | |
| GW/135 | 170,160 | |
| general area(ceiling) | 170,170,120,170 | |
| general area(K1768) | --- | "no sticker was found" |
| general area(cable tray) | --- | "no sticker found" |
| | 120 | should be two stickers on |
| | 120 | these |
| | 120 | |
| general area(K6442) | 140 | |

TABLE B

This table is based on PG&E's data sheets for Teletemp Stickers which were provided to SLOMFP. Given the cumbersome procedure and data forms, the accuracy of this information cannot be guaranteed.

Teletemp Sticker Temperature Readings, Unit 2

| item: | **2R5** (4/93) | |
|---|---|---|
| FCV-37 | 110,110 | |
| FCV-38 | --- | "no stickers found" |
| FCV-95 | 160,160 | |
| FCV-438 | 110, ? | "only 1 sticker found" |
| FCV-439 | 110,120 | |
| FCV-440 | 120,160,120,140 | |
| FCV-441 | 140,160,140,160 | |
| FCV-658 | 100,100 | |
| FCV-659 | 100,100 | |
| FCV-749 | 110,110 | |
| FCV-750 | 150,150 | |
| 8000A | 140,140 | |
| 8000B | 150,150 | |
| 8000C | 150,150 | |
| 8078A | 170,170 | |
| 8078B | 170,170 | |
| 8078C | 170,170 | |
| 8078D | 170,170 | |
| 8112 | 110,110 | |
| 8701 | 140,140 | |
| 8702 | 140,160 | |
| 8703 | 100,100 | |
| RE-73 | 130,130 | |
| RE-74 | 130,130 | |
| general area(K6126) | | |
| GW/115 | 170,170 | |
| GW/117 | 160 | |
| GW/126 | 160 | |
| GW/133 | 160 | |
| GW/135 | 170 | |
| general area(ceiling) | 170, "0" | |
| general area(K1768) | 170 | |
| general area(cable tray) | 110,110,110,110 | |
| general area(K912) | 130 | |
| general area(K1296) | 170 | |
| general area(K6442) | "could not find old stickers" | |

PART 2

CONTENTION V: THERMO-LAG COMPENSATORY MEASURES

Background

785- SLOMFP's Contention V asserts that

> Thermo-Lag material fails as a fire barrier and, in fact, poses a hazard in the event of a fire or an earthquake. Until this situation is adequately resolved, the license for Diablo Canyon Nuclear Power Plant certainly should not be extended.

37 NRC at 26. The Board limited this contention to the adequacy of PG&E's implementation of the interim compensatory measures required by the NRC in connection with the use of Thermo-Lag at DCNPP. See Prehearing Conference Order, LBP-93-1 at 27,28 as clarified by "Memorandum and Order (Discovery and Hearing Schedules)," (2/9/93) at 2.

786- The NRC has issued a series of NRC Information Notices regarding deficiencies found in Thermo-Lag 330 fire barrier material. Additionally, it has required that nuclear power plants implement interim compensatory measures. See NRC Bulletin 92-01 (6/24/92) and Supplement 1 to NRC Bulletin 92-01 (8/28/92).

787- PG&E's response to this NRC request is documented in PG&E's Response to NRC Bulletin, Supplement 1 (9/28/92), PG&E Exhibit 3. In this response, PG&E identified eleven Thermo-Lag fire areas at DCNPP which are subject to these interim compensatory measures. (See Table 1.)

788- PG&E's compensatory measures include: (1) a roving fire watch where fire detection devices are employed; or (2) a continuous fire watch where fire detection devices are not available. Tr. at 1287,1288.

789- PG&E has utilized the roving fire watch program throughout DCNPP "essentially since Units 1 and 2 have been in operation." PG&E Ts. at 6,7. Therefore, implementation of the interim compensatory measures mandated by the NRC required only that "the tour route was slightly modified to encompass the additional fire areas." PG&E Ts. at 14. "Since the fire watch program is merely an extension of an existing program," the Board ruled that "inquiry into potential deficiencies in the existing program, the fire watch program, would be permissible." Tr. at 1297. The Board further clarified its scope of the contention in stating that it sought information on "whatever is part of the interim compensatory measures..." It admitted that "fire watches are, of course, a major part," but "they may not be the only part." Tr. at 1298,1299. Hence, it was established that the Board allowed for discussion all aspects of the fire protection program at DCNPP in all fire areas, not exclusively the eleven containing the Thermo-Lag material.

790- Witnesses for PG&E included: David Cosgrove, Supervisor of Safety and Fire Protection Group at DCNPP; and Robert Powers, Manager of the Nuclear Quality Services Department within PG&E's Nuclear Power Generation Business

Unit. The NRC Staff presented the testimony of Patrick Madden, Senior Fire Protection Engineer, Office of Nuclear Reactor Regulation; and Mary Miller, Senior Resident Inspector at DCNPP. SLOMFP offered no witnesses, but presented their case through cross-examination and the introduction of PG&E Licensee Event Reports ("LERs").

GENERAL FINDINGS REGARDING CONTENTION V

791- **Finding: PG&E has not demonstrated reasonable assurance that its interim compensatory measures can and will be reliably implemented until such time as the generic Thermo-Lag issue is resolved.** The Board finds that PG&E's defense-in-depth fire protection program at DCNPP has been shown to be vulnerable to recurring equipment failure and to the resultant errors and oversights made by inadequately prepared personnel.

"Defense-in-Depth":

792- PG&E's fire protection program utilizes a "defense-in-depth" approach. This includes: (1) prevention; (2) detection/suppression; and (3) mitigation. "Thermo-Lag fire barriers...are part of the mitigation echelon of fire protection." Fire watches "serve as part of the detection/suppression component of defense-in-depth." PG&E Ts. at 4. SLOMFP introduced into evidence documents - all of recent vintage - whose contents demonstrated the vulnerability of these "defenses" at DCNPP. The incidents cited by SLOMFP involve the failure by personnel to implement fire watches in order to compensate for impaired detection and suppression equipment. Of particular concern are the recurring problems and challenges which have resulted from PG&E's fire detection alarm system. The specific events are discussed in detail below.

793- **Finding: Inoperable fire detection/suppression equipment, coupled with the failure by personnel to implement or perform compensatory fire watches, compromises the critical detection/suppression component of PG&E's defense-in-depth fire protection program and jeopardizes the safe operation of the plant.**

Fire Watch Personnel:

794- PG&E has testified to the fact that if "a problem occurs during the performance of an hourly firewatch round that causes a delay, the firewatch has been instructed to call or page the firewatch foreman, the Industrial Fire Officer or ultimately the Operations Shift Supervisor, if necessary, to arrange for assistance in completion of the hourly patrol." PG&E Ts. at 11,12. The fire watch personnel have easy access to telephones, and they carry pagers with them. Tr. at 1305.

795- In one documented instance, however, the individual "had the communication capability," but he "didn't utilize it." Tr. at 1306. In this incident, which occurred on 9/17/91, the individual was detained in the radiologically controlled area due to radon contamination. Because he chose not to communicate his situation with the fire watch foreman, the Industrial Fire Officer or the Operations Shift Supervisor, the "roving watch tour was not performed for two hours. This event is documented in LER 1-91-015-00, dated October 16, 1991." PG&E Ts. at 17 and Tr. at 1303-1307.

796- The Board finds this situation to be of concern because, although PG&E provided adequate equipment for communication, it was unable to provide the individual with the common sense to use it. The public relies on the good judgment of the individuals employed by PG&E to ensure that the plant operates safely. Yet, as noted below in other specific events, PG&E has been unable to provide reasonable assurance that its employees will use sound judgment. The Board finds that the adequate implementation of PG&E's fire protection program at DCNPP is highly vulnerable to personnel error.

797- **Finding: Human error and inadequate understanding jeopardizes the adequacy of PG&E's implementation of compensatory fire protection measures at DCNPP.**

SPECIFIC FINDINGS REGARDING CONTENTION V

MFP Exhibit F-1A: LER 1-91-020-00 (3/31/92)

Transcript pages: 1360-1366

798- LER 1-91-020-00 (3/31/92), MFP Exhibit F-1A, described an incident that occurred on 11/30/91 in which a continuous fire watch with backup fire suppression equipment was not established in Unit 1 solid state protection system (SSPS) room in accordance with the plant's technical specifications. MFP Exhibit F-1A at 1.

799- A continuous fire watch with backup fire suppression equipment was required in order to compensate for a damaged ceiling tile which rendered the Halon system in the SSPS room inoperable. Technical specifications require that these measures be implemented within one hour of discovering a damaged ceiling tile in that room. Id. at 2. PG&E has determined that the Halon system was inoperable from 11/30/91 until 12/13/91. Id. at 3. Yet, no compensatory measures were ever implemented. PG&E found the root cause of this event to be "lack of available design information. No readily available document specified that the integrity of the SSPS room ceiling must be maintained for SSPS room Halon system operability." Id. at 4. PG&E did not realize that the SSPS room ceiling performs a gas barrier function in maintaining adequate Halon concentration for fire suppression. Id. at 1.

800- PG&E's investigation into previous occurrences revealed that "there have been instances when the integrity of an SSPS room ceiling has been challenged or considered part of other events which could have affected operability of the SSPS room Halon systems." Id. at 2.

801- In this incident, PG&E failed to recognize an impaired fire protection system. Moreover, this oversight has occurred on more than one occasion. As a result, compensatory fire protection measures were not implemented.

802- PG&E considers the Halon system to function as "fire suppression" in its defense-in-depth scheme. Tr. at 1362. With this system impaired and the absence of the required compensatory continuous fire watch with backup fire suppression, PG&E failed to provide fire suppression protection for the equipment in the SSPS room. A critical element in PG&E's "defense-in-depth" approach was, hence, lacking. The Licensing Board finds that, in this incident, fire protection at DCNPP was compromised. We find it particularly disturbing that PG&E was unaware of this deficiency until March 3, 1992 (MFP Exhibit F-1A at 4) - many months after the tile had been repaired.

MFP Exhibit F-2: LER 1-92-014-00 (10/7/92)
Transcipt pages: 1290-1299,1342

803- LER 1-92-014-00 (10/7/92), MFP Exhibit F-2, addresses three events involving PG&E's failure to implement continuous fire watches in order to compensate for inoperable smoke detectors and fire barrier impairments in fire detection zone A10. This fire detection zone monitors the 480 volt switchgear rooms for Unit 1 and is comprised of several distinct areas. MFP Exhibit F-2 at 2. "These rooms contain safe shutdown equipment associated with the 480 Volt vital power supplies and cabling/equipment associated with hot shutdown panel instrumentation and control." Id. at 7.

804- The fire barrier impairments were due to modifications being made to the masonry block wall. Id. During construction, a continuous fire watch was in place. But when construction activities stopped for the day, this watch was replaced with a roving hourly watch. Id. at 3.

805- The first event occurred on 9/3/92. A faulty smoke detector in zone A10 went into alarm. Because a continuous fire watch was already in place, no additional action was required. However, once construction stopped, the roving hourly fire watch was put into place and resulted in a violation of the plant's technical specifications. PG&E determined the root cause of this incident to be personnel error in that

> operations personnel failed to understand the interrelationship between the faulted detection zone and the fire barrier area when interpreting the compensatory measures specified in the technical specifications. Also, the computerized TS fire barrier impairment tracking system did not accurately reflect the status of existing impaired barriers. Id. at 6.

PG&E found the contributory causes to be

> 1. The computer that processes the fire detection system alarms annunciates differently than other control room annunciator alarms. When the annunciator is reset at the Fire Alarm Control Panel, the main annunciator light is

extinguished and there is no control board feature to re-alert the operator of the existing condition. It is incumbent on the operator after acknowledging the alarm to investigate the cause, otherwise there is nothing on the main annunciator to remind one that the alarm exists.

2. The fire detection computer Operation Procedure... did not clearly describe the impact of an inoperable smoke detector on the other detectors in the same zone, nor did it address the impact of an inoperable detector on existing fire barrier impairments that credit the detection system as a compensatory measure.

3. DCPP training sessions do not emphasize that a smoke detector in alarm impacts the reflash capabilities of the detection system and may impact more than one fire area.

4. There is a deficiency within the Annunciator Response Procedure... The current sequence of actions that an operator performs when an alarm is received allows the annunciator alarm to be acknowledged, and hence silenced, before the situation is resolved.

Id. at 6,7.

806- The second event occurred on the following day, 9/4/93, for the same reasons as noted in the first event. On this day, however, the Shift Foreman questioned the adequacy of a roving fire watch in the area with the faulty detector. As a result, a continuous fire watch was established and the smoke detector was repaired. Id. at 3.

807- The third event occurred on 9/15/93, during 1R5. When a detector in zone A10 went into alarm, a Unit 1 operator acknowledged the main annunciator alarm and a Unit 2 operator investigated the cause of the alarm. After finding that no fire existed, he returned to the control room. Meanwhile, the Unit 1 personnel reset the main annunciator alarm, thereby rendering zone A10 detectors inoperable. Id. at 4. PG&E

found the root cause of this event to be that the Unit 2 operator did not notify the Unit 1 personnel of the zone A10 alarm status (that he had not attempted to reset the Fire Zone Alarm Panel). Id. at 6.

**808- Finding: Communication was a problem in the third event.**

809- As stated above, PG&E identified a failure in communication as the root cause of the third event. This communication problem has previously been noted by the Board in regards to numerous maintenance events and represents a significant and repetitive problem at DCNPP. See General Findings for Contention I regarding Lack of Communication and/or Coordination.

**810- Finding: In all three incidents, personnel were not equipped to understand/interpret the required compensatory measures.**

811- PG&E's corrective actions to prevent recurrence of these events included revision of the plant's administrative procedures, retraining, an incident summary and clarification of the operating procedure to address the fact that an alarming detector renders the detector zone inoperable. Id. at 8,9. Clearly, the individuals involved in these events experienced a great deal of confusion - and with good reason. These people had to deal with, not only the compensatory measure requirements specified in the technical specifications, but with an impaired computerized tracking system and an extremely unusual fire detection system. Id. at 6. The Board finds that PG&E's employees were not adequately prepared to effectively handle the complicated problems that they encountered. Moreover, the Board is concerned that no amount of training or procedural revisions can prevent a recurrence of a similar event if the fire detection alarm system is inherently problematic.

MFP Exhibit F-5: LER 2-92-006-00 (11/25/92)

Transcript pages: 1324-1326

812- PG&E addressed two events in LER 2-92-006-00 (11/25/92), MFP Exhibit F-5. The first event occurred on 10/30/92 and involved inoperable fire detectors in detection zone B-8, the Unit 2 auxiliary and fuel handling building ventilation area. Fire detection in this zone "monitors the equipment that provides outside air for ventilation cooling to various areas and rooms of the auxiliary and fuel handling buildings. Major equipment includes the carbon filters, high efficiency particulate air (HEPA) filters, roughing filters, and associated fans." MFP Exhibit F-5 at 2.

813- On several occasions during the months of September and October of 1992 (9/6,9/25/10/19,10/24,10/30), "the detection zone B-8 fire detectors repeatedly alarmed and the zone was declared inoperable." Id. at 3. The plant's technical specifications requires that, within one hour of discovery of the impaired equipment, a fire watch patrol be established to inspect the area at least once per hour. Id. However, no compensatory fire watches were established for the event that occurred on 10/30/92. PG&E determined the root cause to be "personnel error due to inadequate knowledge or the plant problem report processing program by the SCO who responded to the fire alarm. The SCO incorrectly concluded that work had not been completed on the problems and that the compensatory measures were still in place." Id. at 5,6. PG&E identified numerous contributory causes of this event: (1) Undocumented replacement of the plant problem report sticker; (2) The most probable cause for the spurious alarms was the labels on the filter modules; (3) Because of the numerous spurious alarms associated with fire detectors in the plant, the organizations involved have established a practice of tolerating such alarms and not rigorously searching for the causes of spurious alarms; (4) The design of the fire alarm system contributed to these events in that the system allows one detector in alarm to render the entire zone inoperable; (5) The fire alarm panels and alarms are normally attended by the control room SCO or the Control Operator. Information as to whether a compensatory measure was in place was available in the control room (SFM's office), but the control room operators were not aware of this information. Id. at 6.

814- On 10/30/92, fire zone B-8 had no reliable fire detection in place for some unspecified period of time - the alarms were not operable and a roving fire watch was not established. The Board finds that this situation jeopardized the safe operation of the plant. Moreover, this event has demonstrated even greater concerns than a missed fire watch. We find that:

**815- Finding: PG&E's corrective actions were insufficient to prevent recurrence of the event.**

816- Recurring problems with spurious alarms cause the zone to be repeatedly placed in and out of operable status. Id. at 4. This situation, as noted above, acclimates personnel to the alarms and decreases their level of attentiveness to a potential problem. Although the problem of spurious alarms has been identified as a contributory cause of this event (Id. at 6), PG&E took no action to remedy this situation. PG&E has identified the design of the alarm system also to have contributed to the event. Id. Yet, PG&E implemented corrective action to train personnel on how to better deal with the spurious alarms, but no mention was made of correcting the source of the problem - the alarm system. See MFP Exhibit F-5 at 7,8.

**817- Finding: Communication was a problems in this event.**

818- The control room operators were not aware that they had access to information as to whether or not a compensatory measure was in place. Id. at 6. This was critical information, and apparently there exists no effective method at DCNPP to ensure that the information is communicated to the appropriate individuals. The Board finds this to be another example of poor communication between different groups of individuals. See General Findings for Contention I regarding Lack of Communication and/or Coordination.

**819- Finding: Plant personnel are not equipped to deal with the spurious fire alarms.**

820- Inadequate understanding of the plant report processing program by the responsible individual (Id. at 5,6) is inexcusable. The public relies on plant personnel to protect their health and safety. The Board finds that, in this incident, PG&E has failed to ensure that its personnel are adequately prepared to do so.

821- The second event addressed in PG&E's report occurred on 11/14/92 and, again, involved fire detection impairment and failure to implement the required compensatory fire protection measures. Id. at 1. This event took place in fire detection zone B-2 which monitors equipment in the Component Cooling Water (CCW), charging pump, and containment spray pump rooms for Unit 2. There was one "fire barrier impairment penetration" in this zone which requires a continuous fire watch within one hour when the detectors are inoperable. Id. at 2.

822- In this event, the main annunciator "Fire System Trouble" activated. An operator reset the alarm at the back panel while the main annunciator and the Honeywell system were still locked in alarm. A moment later, zone B-2 came back into alarm. Approximately 5 minutes later, the operator reset the Honeywell panel and the main annunciator with zone B-2 unknowingly back in alarm. "Since the fire panel is out of sight of control room personnel during routine operations and the main annunciator was clear, the operator believed that detection zone B-2 was operable and no further actions were taken." Id. at 3,4. PG&E determined the root cause to be "personnel error due to improper handling of the spurious fire alarm. The fire detector had alarmed twice in a 24-hour period, but was reset and treated as an operable alarm. No continuous fire watch was provided since the control room personnel believed the system was operable." Id. at 6. PG&E identified three contributory causes. See contributory causes #3,4,5 above.

823- Again, on 11/14/92, fire zone B-2 had no reliable fire detection in place - the alarms were not operable and a continuous fire watch was not established. The Board finds this to be another situation in which the safe operation of the plant was jeopardized due to personnel error. Furthermore, this event, also, has demonstrated concerns other than a missed fire watch. See Findings for zone B-8 above.

824- In conclusion, the Board finds that these two events (and others in evidence) illustrate the fallibility of equipment and plant personnel at DCNPP. As has been stated previously, there exists one fire watch program at DCNPP, and problems occur in that program. These problems threaten the reliability of PG&E to adequately implement fire protection measures at DCNPP, generally and in relation to Thermo-Lag.

MFP Exhibit F-3: LER 1-92-008-00 (7/22/92)

Transcript pages: 1328-1339

825- On 6/23/92, an equipment tagout request was made in order to perform maintenance on the fire sprinkler system that protects the Component Cooling Water and Centrifugal Charging Pump areas in Unit 1. Technical specifications requires that, within one hour of rendering a sprinkler system inoperable, a continuous fire watch be established with backup fire suppression equipment "for those areas in which redundant systems or components could be damaged." LER 1-92-008-00 (7/22/92), MFP Exhibit F-3 at 2.

826- In processing the equipment tagout request, however, "neither the Senior Control Operator nor the Auxiliary Operator actually implementing the requests noted the instructions on the equipment tagout request, which stated that a continuous fire watch was required when the system was out-of-service." Id. As a result, a sprinkler system was unavailable and was without the required continuous fire watch with backup suppression equipment for six hours and 48 minutes. Id. at 4.

827- PG&E determined the root cause to be "personnel error by a licensed Shift Foreman. Upon reviewing the equipment tagout request, the Shift Foreman did not identify the TS requirements." Id. PG&E found the contributory cause to be the failure of the Senior Control Operator and the Auxiliary Operator to identify that a continuous fire watch would be required once the sprinkler system was rendered inoperable. Id.

**828- Finding: Three PG&E personnel failed to recognize and implement the plant's technical specification requirements.**

829- Three qualified PG&E employees failed to recognize that a continuous fire watch with backup suppression equipment was required for this maintenance procedure. Id. Because the instructions regarding this compensatory fire protection requirement were stated on the equipment tagout request (Id. at 2), the Board can find no reasonable explanation for the occurrence of this event. Again, we find another example in which PG&E has failed to implement a compensatory fire protection measure in a timely manner due to personnel error. In this instance, the oversight has particular significance due to the fact that several individuals had the opportunity to prevent this event, yet failed to do so.

830- The Board notes, too, that MFP Exhibit F-3 addresses three previous similar events - all determined to be caused by personnel error. See MFP Exhibit F-3 at 5,6. The Licensing Board thus concludes that shortcomings of PG&E personnel jeopardize the adequacy of the overall implementation of compensatory fire protection measures at DCNPP - not exclusively those involving Thermo Lag fire areas.

<u>MFP Exhibit F-6:</u> LER 1-92-028-00 (12/28/92)

Transcript pages: 1341-1343

831- The fire detection system at DCNPP is comprised of individual detectors grouped into zones and a set of centralized alarm panels located within the control room. When an individual detector alarm is activated, the signal is received by the alarm panels and the associated indicator light illuminates for the affected zone. When the fire detection computer receives an alarm signal, the fire detection computer initiates an audible alarm and the main annunciator window to alert the control room operators. LER 1-92-028-00 (12/28/92), MFP Exhibit F-6, at 3.

832- On 10/1/92 and, again, on 11/26/92, PG&E's fire detection computer malfunctioned, rendering the fire detection system inoperable and requiring implementation of a roving hourly fire watch. <u>Id.</u> at 1. The malfunction of the computer "inhibited the ability for the detection alarm signals to annunciate in the control room, without providing a system trouble alarm to alert the operators of the problem." <u>Id.</u> at 5. The required compensatory measure for a fire detection computer failure "is to station a continuous fire watch at the Data Gathering Panels... so that an inaudible alarm at these panels can be identified and to immediately alert the Control Room operators of the condition." Id. at 3.

833- In both instances, "the computer malfunction had not been identified and a roving fire watch not implemented, therefore TS 3.3.3.8 and 3.7.10 were not met." Id. at 2. In fact, the computer malfunction that occurred on 10/1/92 was not discovered until 11/27/92 when PG&E reviewed previous fire detection computer failures. Id. at 2,5. The fire detection computer failed for 29 minutes on 10/1/92, and it failed for 14-15 hours on 11/26/92. Tr. at 1342.

834- PG&E has testified that the computer malfunction was attributed to a computer software problem that has since been corrected. Tr. at 1343. PG&E has also identified several contributory causes of the computer malfunction, one being that DCNPP "was omitted from the list of technical bulletins recipients and did not receive the vendor mandatory system repairs bulletin." MFP Exhibit F-6 at 6.

**835- Finding: The malfunction of the fire detection computer significantly impaired the fire protection program at DCNPP.**

836- PG&E relies on a computer to alert the control room operators of a potential fire. The computer communicates through audible signals. But when the computer malfunctions, as it has been documented to have occurred on two occasions, these audible signals fail to activate. Furthermore, no alarm, signal or any kind of an indication is provided to the operators to inform them that the computer is no longer functioning properly. Id. at 3. In one instance, it took 14-15 hours before this fire detection computer malfunction was identified and compensatory fire protection measures implemented. In the other incident, PG&E was fortuitous in that the computer malfunctioned for only 29 minutes. Yet, that malfunction was not identified until many weeks after the event. Tr. at 1342 and MFP Exhibit F-6 at 5.

837- PG&E has assured us that the computer problem has been resolved, yet the Board is concerned that, because there is no system to alert the operators of a malfunction, similar situations could arise in the future. The Board's concern is compounded by PG&E's previous interactions with the vendor. See information on contributory causes, Id. at 6.

838- The Board finds that this event represented a significant reduction in PG&E's defense-in-depth fire protection program. Furthermore, an inoperable fire detection system effects the total fire protection program at DCNPP, including the areas containing Thermo-Lag fire barrier material.

CONCLUSIONS OF LAW

839- Based on the foregoing evidence and findings of fact, the Licensing Board has determined that PG&E has not met its burden of proof with respect to either Contention I or Contention V. The Board has not found reasonable assurance that the plant can be operated until the years 2023 and 2025 in a manner that will ensure the health and safety of the public.

840- Accordingly, the Licensing Board denies PG&E's license amendment request that was filed on July 9, 1992.

Respectfully submitted,

Diane Curran /g.z.

Diane Curran

Harmon, Curran, Gallagher & Spielberg
c/o IEER
6935 Laurel Avenue Suite 310
Takoma Park, MD 20912
(301) 270-5518

Jill ZamEk

Jill ZamEk

San Luis Obispo Mothers for Peace
P.O. Box 164
Pismo Beach, CA 93448
(805) 773-3881

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NUCLEAR REGULATORY COMMISSION

'93 NOV 23 P3:46

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

OFFICE OF SECRETARY
DOCKETING & SERVICE
BRANCH

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

CERTIFICATE OF SERVICE

I hereby certify that copies of "San Luis Obispo Mothers for Peace Proposed Findings of Fact and Conclusions of Law" in the above-captioned proceeding have been served on the following by deposit in the United States mail, first class, on November 19, 1993. In addition, a copy of this document in Work Perfect 5.1 format on floppy disk has been included with the copy to Judge Bechhoefer.

Charles Bechhoefer Chairman
Administrative Judge
Atomic Safety and Licensing Board
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Frederick J. Shon
Administrative Judge
Atomic Safety and Licensing Board
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Jerry R. Kline
Administrative Judge
Atomic Safety and Licensing Board
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Office of Commission Appellate Adjudication
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Office of the Secretary
Attn. Docketing and Service Section
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Adjudicatory File
Atomic Safety and Licensing Board Panel
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Ann P. Hodgdon, Esq.
Office of the General Counsel
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Joseph B. Knotts, Jr., Esq.
Winston & Strawn
1400 L. Street, N.W.
Washington, DC 20005

Christopher Warner, Esq.
Richard Locke, Esq.
Pacific Gas and Electric Co.
77 Beale Street
San Francisco, CA 94106

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

Edward O'Neill
Peter Arth, Jr.
Truman Burns
Robert Kinosian
Peter G. Fairchild, Esq.
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Jill ZamEk

Jill ZamEk
San Luis Obispo Mothers for Peace