April 20, 2004

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

SUBJECT: DIABLO CANYON POWER PLANT, UNIT NO. 1 (TAC NO. MB9146) AND UNIT NO. 2 (TAC NO. MB9147) - ISSUANCE OF AMENDMENT RE: EXTENSIONS OF THE COMPLETION TIMES FOR RESTORING AN INOPERABLE DIESEL GENERATOR FROM 7 DAYS TO 14 DAYS

Dear Mr. Rueger:

The Commission has issued the enclosed Amendment No. 166 to Facility Operating License No. DPR-80 and Amendment No. 167 to Facility Operating License No. DPR-82 for the Diablo Canyon Power Plant, Unit Nos. 1 and 2, respectively. The amendments consist of changes to the Technical Specifications (TS) in response to your application dated May 29, 2003, and its supplements dated November 5 and December 23, 2003.

The amendments revise Technical Specification (TS) 3.8.1, "AC Sources-Operating," to extend the completion times for the required actions associated with restoration of an inoperable diesel generator (DG). Staff acceptance of the proposal extends the completion times for restoring an inoperable DG from 7 days to 14 days. The proposed changes provide increased flexibility in the scheduling and performance of on-line DG maintenance, improved allocation of maintenance resources, reduction of DG-related unplanned plant shutdowns or requests for a Notice of Enforcement Discretion, and increased DG availability resulting in reduced shutdown risk.

A copy of the related Safety Evaluation is enclosed. The Notice of Issuance will be included in the Commission's next regular biweekly *Federal Register* notice.

Sincerely,

/RA/

Meena Khanna, Project Manager, Section 2
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-275
and 50-323

Enclosures: 1. Amendment No. 166 to DPR-80
2. Amendment No. 167 to DPR-82
3. Safety Evaluation

cc w/encls: See next page

A copy of the related Safety Evaluation is enclosed. The Notice of Issuance will be included in the Commission's next regular biweekly *Federal Register* notice.

Sincerely,
/RA/
Meena Khanna, Project Manager, Section 2
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***SE Inputs**
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ACCESSION NO.: ML041120264 NRR-058

OFFICE	PDIV-2/PM**	PDIV-2/PM	PDIV-2/LA**	EEIB*	SPSB*
NAME	MKhanna	GShukla	EPeyton	RJenkins	MRubin
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cc:

NRC Resident Inspector
Diablo Canyon Power Plant
c/o U.S. Nuclear Regulatory Commission
P.O. Box 369
Avila Beach, CA 93424

Mr. Pete Wagner
Sierra Club California
2650 Maple Avenue
Morro Bay, California 93442

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

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

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

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

Regional Administrator, Region IV
U.S. Nuclear Regulatory Commission
Harris Tower & Pavillion
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011-8064

Richard F. Locke, Esq.
Pacific Gas & Electric Company
P.O. Box 7442
San Francisco, CA 94120

Mr. David H. Oatley, Vice President
and General Manager
Diablo Canyon Power Plant
P.O. Box 56
Avila Beach, CA 93424

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

Mr. Ed Bailey, Radiation Program Director
Radiologic Health Branch
State Department of Health Services
P.O. Box 942732 (MS 178)
Sacramento, CA 94234-7320

Mr. James D. Boyd, Commissioner
California Energy Commission
1516 Ninth Street (MS 31)
Sacramento, CA 95814

Mr. James R. Becker, Vice President
Diablo Canyon Operations
and Station Director
Diablo Canyon Power Plant
P.O. Box 3
Avila Beach, CA 93424

PACIFIC GAS AND ELECTRIC COMPANY

DIABLO CANYON NUCLEAR POWER PLANT, UNIT NO. 1

DOCKET NO. 50-275

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No.166
License No. DPR-80

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Pacific Gas and Electric Company (the licensee) dated May 29, 2003, and its supplements dated November 5 and December 23, 2003, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. DPR-80 is hereby amended to read as follows:

(A) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 166, are hereby incorporated in the license. Pacific Gas and Electric Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where otherwise stated in specific license conditions.

3. This amendment is effective as of its date of issuance, and shall be implemented within 180 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Stephen Dembek, Chief, Section 2
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: April 20, 2004

PACIFIC GAS AND ELECTRIC COMPANY

DIABLO CANYON NUCLEAR POWER PLANT, UNIT NO. 2

DOCKET NO. 50-323

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 167
License No. DPR-82

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Pacific Gas and Electric Company (the licensee) dated May 29, 2003, and its supplements dated November 5 and December 23, 2003, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. DPR-82 is hereby amended to read as follows:

(A) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 167, are hereby incorporated in the license. Pacific Gas and Electric Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where otherwise stated in specific license conditions.

3. This license amendment is effective as of its date of issuance, and shall be implemented within 180 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Stephen Dembek, Chief, Section 2
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: April 20, 2004

ATTACHMENT TO LICENSE AMENDMENT NO. 166

TO FACILITY OPERATING LICENSE NO. DPR-80

AND AMENDMENT NO. 167 TO FACILITY OPERATING LICENSE NO. DPR-82

DOCKET NOS. 50-275 AND 50-323

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

REMOVE	INSERT
3.8-1	3.8-1
3.8-2	3.8-2

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 166 TO FACILITY OPERATING LICENSE NO. DPR-80

AND AMENDMENT NO. 167 TO FACILITY OPERATING LICENSE NO. DPR-82

PACIFIC GAS AND ELECTRIC COMPANY

DIABLO CANYON POWER PLANT, UNITS 1 AND 2

DOCKET NOS. 50-275 AND 50-323

1.0 INTRODUCTION

By application dated May 29, 2003, and its supplements dated November 5 and December 23, 2003, Pacific Gas and Electric Company (PG&E or the licensee) requested changes to the Technical Specifications (Appendix A to Facility Operating License Nos. DPR-80 and DPR-82) for the Diablo Canyon Power Plant, Units 1 and 2. The proposed amendments would revise Technical Specification (TS) 3.8.1, "AC Sources-Operating," to extend the allowable completion times (CT) for the required actions associated with restoration of an inoperable diesel generator (DG). Specifically, the proposed changes would extend the completion times for restoring an inoperable DG from 7 days to 14 days. These changes would provide increased flexibility in the scheduling and performance of on-line DG maintenance, improved allocation of maintenance resources, reduction of DG-related unplanned plant shutdowns or requests for a Notice of Enforcement Discretion, and increased DG availability resulting in reduced shutdown risk.

The staff issued a request for additional information on August 25, 2003, and the licensee provided its responses by letters dated November 5 and December 23, 2003. The staff has reviewed the proposed changes from a probabilistic risk assessment (PRA) perspective as well as from a deterministic perspective. The staff's evaluation of the licensee's proposed revisions is provided below.

The November 5 and December 23, 2003, supplemental letters provided additional clarifying information, did not expand the scope of the application as originally noticed, and did not change the NRC staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on June 24, 2003 (68 FR 37581).

2.0 REGULATORY EVALUATION

The staff finds that the licensee, in Section 5.2 of its submittal, identified the applicable regulatory requirements. The regulatory requirements for which the staff based its acceptance are provided below.

General Design Criterion (GDC)-17, "Electric Power Systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to Title10, Part 50, of the Code of Federal Regulations (CFR) requires, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of structures, systems, and components that are important to safety. The onsite system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. The offsite power system is required to be supplied by two physically independent circuits that are designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. In addition, this criterion requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as a result of loss-of-power from the unit, the offsite transmission network, or the onsite power supplies.

GDC 18, "Inspection and Testing of Electric Power Systems," requires that electric power systems that are important to safety must be designed to permit appropriate periodic inspection and testing. Section 50.36, "Technical Specifications," requires a licensee’s TSs to establish limiting conditions for operation (LCOs), which include CTs for equipment that is required for safe operation of the facility. Section 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," requires that preventive maintenance activities must not reduce the overall availability of the systems, structures and components.

NRC Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," describes a risk-informed approach, acceptable to the NRC, for assessing the nature and impact of proposed licensing basis changes by considering engineering issues and applying risk insights.

RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," describes an acceptable risk-informed approach specifically for assessing proposed TS changes in allowed outage times (AOTs). These RGs also provide acceptance guidelines for evaluating the results of such evaluations.

3.0 TECHNICAL EVALUATION

The staff has reviewed the licensee's regulatory and technical analyses in support of its proposed license amendments which are described in Sections 4 and 5 of the licensee's submittal. The detailed evaluation, below, will support the conclusion that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

3.1 Proposed Changes to Technical Specifications

In its application, the licensee proposed the following changes to TSs 3.8.1:

1. TS 3.8.1 – in the "Actions" column, for Condition A, under the Completion Time for Required Action A.2, after the phrase "72 hours AND" replace the "10 days" with "14 days."

2. TS 3.8.1 – in the "Actions" column, for Condition B, under the Completion Time for Required Action B.4, replace the phrase "7 days AND 10 days" with "14 days."

The proposed changes will provide increased flexibility in the scheduling and performance of the on-line DG maintenance, improved allocation of maintenance resources, avoidance of DG-related unplanned plant shutdowns or requests for a Notice of Enforcement Discretion, and improved DG availability during shutdowns. The proposed changes were justified based upon a risk-informed and traditional engineering (defense-in-depth) evaluation.

LCO 3.8.1, Condition B.4, currently requires that, if one of the emergency diesel generators (EDGs) becomes inoperable, the inoperable DG be restored to the operable status within 7 days. The licensee has proposed to increase the required CT for a single inoperable DG from the current 7 days to 14 days.

The licensee states that the proposed CT of 14 days provides adequate time to perform normal preventive DG inspections and maintenance requiring disassembly of the DG and to perform post-maintenance and operability tests required to return the DG to the operable status. The proposed change will also provide increased flexibility in the scheduling and performance of on-line DG maintenance, improve allocation of maintenance resources, avoid DG-related unplanned plant shutdowns or requests for a Notice of Enforcement Discretion, and improve DG availability during shutdowns. In addition, the licensee states that it intends to use the proposed 14-day CT to perform planned maintenance or inspections at a frequency of no more than once per DG per operating cycle for each DG. Beyond that, the licensee will continue to minimize DG unavailability due to planned maintenance in accordance with the goals of 10 CFR 50.65 (the Maintenance Rule) to ensure that DG outage times do not degrade operational safety over time. The staff finds the proposed changes to be acceptable based on the evaluation provided below.

3.2 Deterministic Evaluation

Alternate AC Source

At DCPP, any of the three DGs may be used as an alternate AC (AAC) source to provide an alternate source of power in the event of a station blackout (SBO) or in the event of a loss of offsite power (LOOP), when one DG is in the extended outage and the other DGs become unavailable. SBO at DCPP is defined as loss-of-power from the 500 kV and 230 kV switchyards with the failure of two DGs to operate in one of the units. The other unit is assumed to experience only a LOOP. The licensee performed the SBO analysis using the guidance of NUMARC 87-00, Rev. 0. The SBO analysis demonstrated that during an SBO event, the plant could be safely shut down utilizing either buses G or H and their normally connected DGs and, thereby, the third DG and its Bus F were declared the AAC source. However, during an SBO, any of the three DGs may be used as the AAC source. Since the AAC source is a Class 1E DG, it meets the criterion for the AAC source to be available within 10 minutes of the SBO event.

On the basis of the above considerations, the staff concludes that, in the event of an SBO or a LOOP and failure of the operable DGs during the extended CT, power can be supplied from the SBO DG to power all of the needed loads for an SBO or LOOP.

Additional Operational Restrictions

The current TS requirements establish controls to ensure that, in the event a DG is inoperable, the redundant required features that depend on the operable DG as a source of power are verified operable. This provides assurance that a LOOP event will not result in a complete loss of safety function of critical systems during the period in which one of the DGs is inoperable. Since the extension of the DG AOT is based on the finding of a deterministic and probabilistic safety analysis, entry into this action requires that a risk assessment be performed in accordance with a Configuration Risk Management Program (CRMP). The above ensures that a PRA informed process is in place that assesses the overall impact of plant maintenance on plant risk prior to entering the LCO Action statement for planned activities.

Compensatory Measures

By supplemental letter dated December 23, 2003, the licensee has committed to establish the following compensatory measures when the DG is removed from service for maintenance utilizing the 14-day extended CT:

- Maintain periodic communication with the DCPP Switching Center and Transmission Operations during the project to ensure no elective maintenance or testing on the offsite power sources is performed.

- Provide assurance that storms or ocean swell events are not expected during the maintenance period.

- Contact the DCPP Switching Center to verify offsite power sources are not in danger of being lost due to wild land fires, other grid related transients, or scheduled work activities.

- Assure that Operations, Maintenance, Engineering, and the Manager of Operations are notified in the event of external events that may jeopardize offsite power sources, and that they determine if postponement of the DG maintenance is warranted.

- Avoid scheduling site activities that may cause a plant transient on either unit. Exceptions should be authorized in accordance with DCPP Administrative Procedure AD7.DC6, "On-Line Maintenance Risk Management."

- Avoid performing any testing or elective maintenance on either unit unless it is identified on the approved work week schedule. Exceptions may be approved by the shift manager or work week manager.

- Clearly identify and obtain agreement on the maintenance scope before starting. No additions will be made without engineering and operations review, including their impact on post-maintenance test requirements.

- Verify all parts and equipment necessary for the project have been procured and meet quality related checks.
- Support the DG maintenance project on a 24-hour a day schedule.
- Provide on-shift senior management support in the event conditions develop that jeopardize plant operation (such as wild land fires, high ocean swell warnings, or electrical distribution problems).
- Post caution signs on the affected unit's doors to the following rooms requiring shift foreman permission to perform work within:
    - Motor-driven and turbine-driven auxiliary feedwater pump rooms
    - Other two DG rooms
- Verify the other two DGs are operable.
- Perform a walkdown verifying the other two DGs and associated areas are clean and in good material condition with no activities being performed which could jeopardize operation.
- Verify that redundant safety-related systems, subsystems, trains, components and devices that depend on the other two DGs are operable within 24 hours of beginning maintenance.
- Perform no elective maintenance or testing on components required to crosstie the vital 4 kV buses between units as required by DCPP emergency operating procedures.
- Perform no elective maintenance or testing on components (other than normally scheduled surveillances) on either unit's DGs.
- Verify all DG fuel oil transfer system surveillance testing is current for the duration of the project.
- Conduct operator briefings on applicable normal, abnormal and emergency procedures for reactor trip, loss of electrical power, and restoring electrical power, each shift for the duration of maintenance.
- Place the affected unit's redundant equipment (4kV and 480 V) in service or on alternate power supplies.

Deterministic Conclusion

The staff has evaluated the proposed changes to determine whether the applicable regulations continue to be met. The staff concludes that extending the CT for an inoperable DG from the current 7 days to 14 days is acceptable. The staff's conclusion is based on the following four considerations:

(1) The extended CT will typically be used to perform infrequent diesel manufacturer's recommended inspections and preventive maintenance activities.

(2) The extended CT would reduce entries into the LCO and reduce the number of DG starts for major DG maintenance activities.

(3) The AAC DG will be available and capable of powering the inoperable DG bus loads in the event of an SBO or LOOP.

(4) Implementation of the CRMP will be completed during the extended outage.

Further, the staff believes that implementation of compensatory measures would ensure the availability of the remaining sources of AC power during the extended CT and would minimize the occurrence of an SBO. The staff also concludes that the proposed changes will not affect the compliance of DCPP with the requirements of GDCs 17 and 18.

3.3 Probabilistic Risk Assessment Evaluation

The licensee's proposed completion time of 14 days provides adequate time to perform normal preventive DG maintenance and inspections requiring disassembly of the DG and performance of post-maintenance and operability tests required to return the DG to the operable status. The licensee states that it intends to minimize the use of the proposed 14-day DG completion time for planned maintenance to a frequency of no more than once per operating cycle for each DG (three DGs per unit). Further, it is the licensee's intent to continue to minimize the time periods required to complete any unplanned maintenance. DG maintenance will be performed with the same emphasis on timely completion as is currently practiced. Additionally, the licensee will provide the resources necessary to minimize DG unavailability due to unplanned maintenance, as well as managing the risk of such evolutions using the On-Line Risk Management Program. The On-Line Risk Management Program is controlled by Administrative Procedure AD7.DC6, "On-Line Risk Management," which provides guidance for managing plant trip and safety function risk degradation from on-line maintenance, external or internal conditions, as required by 10 CFR 50.65(a)(4). Plant configuration changes for planned and unplanned maintenance of the DGs, as well as the at-power maintenance of other risk-significant equipment, are managed by the On-Line Risk Management Program. This program provides additional assurance that these maintenance activities are performed with no significant increase in the risk of a severe accident.

The licensee has evaluated its proposed DG completion time changes to determine that current regulations and guidelines continue to be met, that adequate defense-in-depth and safety margin provisions are maintained and that any increases in the "at-power" core damage frequency (CDF) and large early release frequency (LERF) are small and consistent with the staff's Safety Goal Policy Statement. The impact on risk of the 14-day completion time is evaluated according to the guidelines in RG 1.177. Additionally, the proposed changes, according to the licensee, are not expected to result in an increase in the total unavailability of each DG (i.e., including all modes), and the changes may sometimes result in a risk decrease for a refueling outage.

In the licensee's PRA model, SBO is treated as the loss of all onsite and offsite AC power. In a station blackout sequence, the operators are instructed to depressurize the steam generators (Emergency Operating Procedure (EOP) ECA 0.0) using the 10 percent steam dump valves or the 40 percent steam dump valves to limit reactor coolant pump (RCP) seal leakage. The turbine-driven auxiliary feedwater (TDAFW) pump is also credited to cool down the reactor coolant system (RCS). These actions reduce RCS temperatures and pressures sufficiently to allow the accumulators to inject. The accumulator inventories provide additional RCS inventory, which must also leak out for core uncovery. The reduced RCS temperatures and pressures limit the rate of seal degradation and markedly reduce the rate of subsequent leakage. Failure of these actions reduces the time available for electric power recovery because the RCP seal leak rate would be higher otherwise. These actions are all considered in the determination of success criteria for the electric power recovery factors.

During SBO scenarios, the PRA assumes that it is important that the operators (1) restore AC power to at least two vital buses by restoring offsite power, recovering diesel generators, or cross tying vital buses, (2) maintain and control auxiliary feedwater flow from an auxiliary feedwater pump, (3) monitor core subcooling and reactor coolant inventory, and (4) monitor DC power availability and take action to extend battery life.

The following should be noted:

- No electric power recovery action is credited for the SBO scenarios in which the pressurizer power operated relief valve (PORV)/safety fails to re-seat, hence resulting in a loss-of-coolant accident (LOCA) path.

- Following recovery of a DG during an SBO operator action, crosstie of two vital buses is modeled.

The risk-informed support for the licensee's proposed 14-day DG completion time is based on maintaining defense-in-depth, quantifying the PRA to determine the changes in at-power CDF and LERF, as well as the incremental conditional core damage probability (ICCDP) and the incremental conditional large early release probability (ICLERP), resulting from the proposed 14-day completion time for the DGs, implementation of the On-Line Risk Management Program, including performance of 10 CFR 50.65(a)(4) risk assessments to control performance of other risk-significant tasks during the DG outage, and consideration of configuration-specific compensatory measures to control risk.

The licensee has evaluated the risk impacts of the proposed new completion time and found them to be acceptable. Overall, at-power risks increase within acceptable guidelines. The impact on risk of the proposed 14-day completion time for restoration of an inoperable DG has been evaluated by the licensee using the staff's three-tiered approach discussed in RG 1.177:

Tier 1 - PRA Capability and Calculational Insights,
Tier 2 - Avoidance of Risk-Significant Plant Configurations, and
Tier 3 - Risk-Informed Configuration Management.

Although RG 1.177 recommends the evaluation of the proposed change on the total risk (i.e., on-line and shutdown risk), the licensee's quantitative evaluation deals only with the on-line risk.

This is probably conservative, since the shutdown risk will likely be reduced as a result of the increased shutdown DG availability that would result from the 14-day (at-power) completion time.

3.3.1 Tier 1: PRA Capability and Calculational Insights

Risk-informed support for the proposed changes is based on an evaluation of PRA calculations performed to quantify the changes in CDF and LERF, as well as the ICCDP and ICLERP, resulting from the 14-day DG completion times.

PRA Capability

The scope, level of detail, and quality of the licensee's PRA (DCPRA) are sufficient, according to the licensee, to support a technically defensible and realistic evaluation of the risk impacts resulting from the proposed DG completion time relaxation to 14 days. The staff finds this acceptable because of the following reasons: (1) the DCPRA used in the licensee's evaluation addresses internal, seismic and fire events at full power, (2) the internal and seismic event models were used directly, whereas the fire model required additional licensee evaluation for these calculations, and (3) the DCPRA is performed for Unit 1, but it is also applicable to Unit 2, because the two units are approximately identical.

The DCPRA is based on the original 1988 DCPP PRA that was performed as part of the long-term seismic program (LTSP). The 1988 DCPRA was a full- scope Level 1 PRA that evaluated internal and external events. The staff reviewed the LTSP and issued Supplemental Safety Evaluation Report (SSER) No. 34, accepting the 1988 DCPRA, which was subsequently updated to support the Individual Plant Examination (IPE) (1991) and the Individual Plant Examination for External Events (IPEEE) (1993). Since 1993, several other updates have been made to incorporate plant and procedural changes, which include: updating plant-specific reliability and unavailability data, improving the fidelity of the model, and incorporating changes based on the Westinghouse Owners Group (WOG) Peer Review comments. These updates will support other applications, such as, on-line maintenance and risk-informed in-service inspection analyses.

Prior to the IPE submittal, the model was enhanced to include the probability of a LOOP subsequent to non-LOOP initiating events. Other improvements to the PRA model since the IPE that affect the licensee's submittal include:

- incorporation of a sixth DG, installed in 1993,
- upgraded auxiliary service water (ASW) system modeling to allow more consistency with the SBO submittal,
- allowance of cross-tie credit for vital 4-kV buses (i.e., one DG feeds loads on two vital buses),
- addition of the 500-kV switchyard model, to supplement the 230-kV switchyard,

- addition of more detailed modeling for transient-induced LOCAs from a LOOP, including application of credits and penalties for a third PORV, and

- updating of initiating event frequencies to reflect data from NUREG-5750.

The DCPRA was recently enhanced to support the analysis of the DG completion time extension submittal. The most significant change made was to the RCP seal LOCA model. The licensee's updated DCPRA now uses the Rhodes RCP Seal Model, as defined in NUREG/CR-5167, "Cost/Benefit Analysis for Generic Issue 23: Reactor Coolant Pump Seal Failure," Appendix A, April 1991, to characterize the RCP seal performance on loss of cooling and seal injection.

The DCPRA includes an evaluation of the containment performance. A simplified LERF model, based on the Level 2 PRA, is used for the calculation of LERF for internal, seismic, and fire scenarios. The DCPRA is a living PRA, which is maintained through a periodic review and update process.

Peer review certification of the DCPRA, using the WOG peer review certification guidelines, was performed in May 2000. This peer review certification was carried out by a team of independent PRA experts from U.S. nuclear utility PRA groups and PRA consultant organizations. This intensive peer review involved two person-months of engineering effort by the review team and provided an assessment of the strengths and limitations of each element of the PRA. On the basis of its evaluation, the certification team determined that, with certain findings and observations addressed, the quality of all elements of the PRA would be sufficient to support risk-significant evaluations with defense-in-depth input relative to the requested completion time relaxation. All of the findings and observations from this assessment, which the review team indicated were important or which involved risk elements that are needed to evaluate the proposed completion time relaxation, were dispositioned. As a result, a number of modifications were made to the PRA model, prior to its use, to support the licensee's proposed changes. A major enhancement was the reanalysis and updating of the pre- and post-initiating events human reliability assessment.

In addition to the peer certification, a limited scope, independent assessment of the DCPRA, was performed by an industry PRA expert prior to the licensee's completion of the relaxed DG completion time analysis. This assessment focused on the elements required to support the 14-day proposed DG completion time.

As a result of the sound basis of the original model, as documented in SSER-34 and NUREG/CR-5726, "Review of the Diablo Canyon Probabilistic Risk Assessment," August 1994, the considerable effort to incorporate the latest industry insights into the PRA, self-assessments, and certification peer reviews, the licensee is confident that the risk evaluation results to support the requested 14-day DG completion time are technically sound and consistent with the expectations for PRA quality set forth in RG 1.177 and RG 1.174. The staff finds this acceptable.

Fire and Other External Events

The licensee conducted a fire analysis as part of the LTSP and updated it to support the 1993 IPEEE. Other than the control room (CR) and the cable spreading room (CSR) fire scenarios, the fire PRA quantifies the CDF associated with most internal fire initiating events using the same linked event tree models as the internal and seismic events analyses. Separate event trees using conservative assumptions were developed for evaluating CR and CSR fire scenarios.

As part of the evaluation of the 14-day DG completion time relaxation, the fire scenarios and models were re-evaluated using the following steps:

1. For non-CR/CSR fire scenarios that are quantified using the event tree models, the figures of merit were directly calculated by the licensee. The results of these calculations are included in the risk metric results later in this section.

2. For fires in the CR and the CSR, the customized fire event trees were reviewed by the licensee to assess the impact of the relaxation in the DG completion time results. The review of these scenarios indicated that their contribution to the change in risk, due to the proposed 14-day DG completion time, is very small.

3. All fire scenarios previously screened during the fire PRA risk evaluation were reviewed to ensure that the screening basis is not significantly affected by the relaxation in the completion times for the DGs. For the affected scenarios, the contribution to risk was reassessed by the licensee for the base case and the DG out-of-service (OOS) cases. This assessment included a review of plant fire events to ensure that the risk from plant-specific fire events was properly included. The licensee's review concluded that the risk impact of the proposed 14-day DG completion time is limited to a class of fire events that could result in a fire-induced LOOP (similar to the event that occurred in May 2000).

The quantitative impacts of these fire-induced LOOP events are incorporated into the values provided in the risk metric results later in this section.

The evaluation of high winds, external floods, and other external events, which was done as part of the IPEEE, revealed no potential vulnerabilities. Thus, the proposed relaxation of the DG completion time has very little effect on the risk profile at DCPP from other external events.

Risk Results and Insights

The results of the risk evaluation are presented in Tables 1, 2, and 3, below. These tables show the results of the baseline risk metric calculations, and the results of the risk metric calculation when the indicated diesel is OOS. The baseline CDF is approximately 5.1E-05/yr, based on the average unavailability of the DGs, using plant-specific data (i.e., the average unavailability based on current completion times and maintenance practices). The total baseline LERF is approximately 2.1E-06/yr. The total baseline CDF and LERF values include contributions from internal, seismic, and fire events. Each of the contributions is listed separately by the licensee in the tables.

From Table 1, contributions to the baseline CDF are partitioned approximately as 60 percent due to seismic events, and 20 percent, each due to internal and fire events. When a DG is OOS, the risk profile remains similar (3 DGs/unit), with internal events becoming slightly more important than fire events, but with seismic events still contributing about 60 percent of the CDF. Internal and seismic CDFs increase due to the importance of the DGs in LOOP events. For seismic events, the concern is a seismically-induced LOOP from low intensity events where the switchyard components fail, but the DGs remain functional due to their substantially higher values of high confidence of low probability of failure (HCLPF).

The contribution of non-LOOP-inducing fire events to CDF decreases because there is a lower fire CDF during the DG OOS time. This is due to the fact that maintenance is constrained on the other DGs, start-up power, AFW, and ASW, as opposed to the average maintenance utilized in the baseline analysis. Fire-induced LOOP events contribute a small amount (less than 4E-07/yr) to the increase in CDF when a DG is OOS.

Table 1

Risk Evaluation Results for DCPP Unit 1 CDF				
CDF (/yr)	Baseline	DG 1-1	DG 1-2	DG 1-3
Internal	8.18E-06	1.25E-05	1.15E-05	1.15E-05
Seismic	3.18E-05	3.56E-05	3.58E-05	3.93E-05
Fire	1.15E-05	1.15E-05	1.12E-05	1.14E-05
Total	5.15E-05	5.95E-05	5.85E-05	6.23E-05

Note: Results also apply to Unit 2, but naming is not symmetrical between units. Equivalent DGs are: 1-1 and 2-2 (Bus H), 1-2 and 2-1 (Bus G), 1-3 and 2-3 (Bus F).

Table 2 shows that risk contributions to the baseline LERF are partitioned approximately 75 percent due to seismic events, and 25 percent due to internal events, with fire contributing less than 1 percent. When a DG is OOS, the risk profile remains similar, with internal events becoming slightly more important and seismic contribution decreasing. The change in fire importance is very small.

Overall, the relative change in LERF is much less than the change in CDF when a DG is unavailable. LERF is dominated by non-isolated SGTR and inter-system LOCA events, which are relatively insensitive to DG availability.

Table 2

Risk Evaluation Results for DCPP Unit 1 LERF				
LERF (/yr)	Baseline	DG 1-1	DG 1-2	DG 1-3
Internal	5.49E-07	6.51E-07	6.32E-07	5.39E-07
Seismic	1.50E-06	1.52E-06	1.49E-06	1.51E-06
Fire	8.11E-09	7.23E-09	4.54E-09	5.30E-09
Total	2.06E-06	2.17E-06	2.13E-06	2.05E-06

Note: Results also apply to Unit 2, but DG naming is not symmetrical between units. Equivalent DGs are: 1-1 and 2-2. 1-2 and 2-1, and 1-3 and 2-3.

In Table 3, the highest estimated increase in CDF takes place when DG 1-3 is OOS, which is about a 21 percent increase, compared to 16 percent and 13 percent increases in CDF for DG 1-1 and DG 1-2, respectively. The enhanced significance of DG 1-3 is that it supplies power to the ASW pump 1-1, the ASW cross-tie valve (FCV-601), and the motor-driven AFW pump 1-3, which are significant contributors to risk during LOOP events. In contrast, DG 1-1 and DG 1-2 support either an ASW pump or a motor-driven AFW pump.

In Table 3, the highest estimated increase in LERF is limited by DG 1-1. The LERF results for DG 1-1 and 1-2 are similar (approximately 6 percent and 4 percent increases, respectively). The increase in LERF for DG 1-3 is very small. The low significance of DG 1-3 to LERF is based on the fact that DG 1-1 and 1-2 support the buses supplying power to the residual heat removal (RHR) Trains 1-1 and 1-2, used for stable end-state decay heat removal in steam generator tube rupture (SGTR_ scenarios). Both buses are needed to establish RHR closed loop cooling for decay heat removal.

Table 3

Increase in CDF/LERF and ICCDP/ICLERP for Each Unit 1 DG			
	DG 1-1	DG 1-2	DG 1-3
Increase in CDF (/yr)	8.0E-06	7.1E-06	1.1E-05
ICCDP	3.1E-07	2.7E-07	4.1E-07
Increase in LERF (/yr)	1.2E-07	7.5E-08	1.4E-09
ICLERP	4.5E-09	2.9E-09	5.4E-11

Note: Results apply to Unit 2, but DG naming is not symmetrical between units. Equivalent DGs are: 1-1 and 2-2, 1-2 and 2-1, and 1-3 and 2-3.

The limiting risk evaluation results are compared in Table 4 with the risk significance guidelines from RG 1.174 for the change in annual average CDF and LERF, and guidelines from RG 1.177 for ICCDP and ICLERP.

- The proposed relaxed DG completion time is calculated by the licensee to increase the annual average "at-power" CDF and LERF by less than 1 percent from the current baseline values. The changes in CDF and LERF are considerably less than the guideline values for these metrics.

- As noted in the previous tables, the ICCDP and ICLERP evaluations are based on DG 1-3 (2-3 for Unit 2) and DG 1-1 (2-2 for Unit 2), respectively. These DGs OOS provide the limiting values for those risk metrics. The calculated values for ICCDP and ICLERP demonstrate that the proposed DG completion time has only a small quantitative impact on plant risk, as they are less than the RG 1.174 and RG 1.177 guideline values, as shown in Table 4.

Table 4

Results of Risk Evaluation for Unit 1		
Risk Metric	Risk Significance Guideline	Risk Metric Results (% of Risk Guideline) Unit 1
Delta CDF (Ave)	< 1.0E-06/yr	2.8E-07/yr (28%)
ICCDP (1)	< 5.0E-07	4.1E-07 (83%)
Delta LERF (Ave)	< 1.0E-07/yr	5.4E-09/yr (5%)
ICLERP (2)	< 5.0E-08	4.5E-09 (9%)

(1) ICCDP value is for DG 1-3 and DG 2-3, which are the limiting DGs for CDF.
(2) ICLERP value is for DG1-1 and DG 2-2, which are the limiting DGs for LERF.

In determining the risk metrics displayed in the above tables, the PRA quantification truncation limits set by the licensee were designed as sufficiently low values to ensure that sequences important to the evaluation are included in the results. The truncation limits for sequence quantification vary based on the initiating event. The truncation limits are set such that the unaccounted for event frequency is less than 1 percent of the total frequency calculated. There was no truncation used by the licensee in generating the cutsets.

The following are factors related to the PRA calculations that are not considered explicitly therein. If added to the quantification, these factors should reduce the calculated impact of the DG unavailability.

- Certain risk-significant equipment combinations would not generally exist voluntarily by following the licensee’s on-line risk management procedure. Some of these configurations are excluded from the CDF and LERF calculations for a DG unavailable by constraining maintenance on other DGs, startup power, AFW, and ASW. If additional undesirable configurations that would generally not be entered were explicitly excluded in the calculations, the calculated risk could be substantially lower.

- The risk metrics calculated by the licensee in the PRA do not take into account compensatory measures beyond the maintenance constraints described previously that the licensee would have in place when using the relaxed DG completion time. However, these compensatory actions (see next section) would reduce risk.

- There is also some risk trade-off between on-line and outage modes that the licensee does not explicitly quantify. Performing DG overhauls on-line rather than during outages will increase DG availability during outages. This can reduce shutdown risk by improving the availability of standby AC power sources for shutdown cooling equipment and other equipment needed to mitigate the events postulated to occur during shutdown. The decrease in risk is not significant, considering that LOOP likelihood may be greater during shutdown modes than while at power. The likelihood of LOOP increases during shutdowns when one of the two offsite power sources is cleared for maintenance, and due to maintenance activities which may trip breakers supplying power from an offsite source.

3.3.2 Tier 2: Avoidance of Risk-Significant Plant Configurations

The licensee's adherence to the current TS requirements will prevent many of the more risk-significant configurations to become manifest. Specifically, there are requirements concerning the operability of offsite power sources and other DGs. Furthermore, LCO 3.8.1 (Condition B) requires that "required feature(s) supported by the inoperable DG" must be declared inoperable when "its required redundant feature(s) is inoperable." This prevents having unavailable front-line structures, systems, and components (SSCs) (e.g., AFW) from the other train without entering more restrictive LCOs, including TS 3.0.3. Thus, except for emergent conditions resulting from equipment failure, it is highly unlikely that these SSCs will be made unavailable during at-power DG unavailability. Even under these unexpected conditions, it is likely that a more restrictive LCO would be entered, requiring corrective action to be taken to return equipment to the operable status.

The Safety Function Determination Program (SFDP), as required by TS 5.5.15, includes provisions for cross-division checks to ensure that a loss of capability to perform a safety function assumed in the accident analysis does not go undetected. TS LCO 3.0.6 establishes requirements regarding supported systems when support systems are found inoperable. Upon entry into TS LCO 3.0.6, a licensee evaluation is required to determine whether there has been a loss of safety function. Additionally, other limitations, remedial actions, or compensatory measures may be identified as a result of the support system inoperability and corresponding exceptions to entering supported system conditions and required actions. The SFDP implements the requirements of TS LCO 3.0.6. Administrative Procedure OP1.DC38, "Safety Function Determination Program," implements the SFDP.

Risk Management and Compensatory Actions

The risk associated with having a DG OOS will be managed by the licensee by adhering to the requirements for the on-line risk assessment and management, as described in DCPP

Procedure AD7.DC6. In addition to the risk directly associated with the DG unavailability, the procedure requires that potentially risk-significant configurations, during the period of DG unavailability, are assessed and managed by the licensee.

The licensee's analysis performed to support the relaxation of the DG completion time specifically constrained maintenance on the affected unit DGs, startup power, the affected unit AFW trains, and all trains of ASW, including the cross-tie (FCV-601). Other compensatory measures and restrictions identified by site risk-management procedures are not quantified, but have an impact on the risk due to an OOS DG. Examples of risk-informed licensee compensatory measures that will be implemented, but are not quantified, that would further reduce the risk of DG maintenance while a plant is on-line include:

- stationing an operator and/or other personnel in the vicinity of ASW pumps and cross-tie valves: this would ensure that personnel are more readily available to establish local ASW cross-tie (e.g., Bus F without power due to DG 1-3 failure), thus increasing the success likelihood.

- provision of guidance to operations for cross-tying buses in the event of a DG failure: if DG 1-3 is unavailable and Bus F is de-energized during a LOOP, cross-tying to re-energize Bus F will recover both AFW and ASW components. This is more effective and reliable than performing mechanical cross-tie operations in both systems.

3.3.3 Tier 3: Risk-Informed Configuration Risk Management Program

The licensee has developed a process for on-line risk assessment and management. Following the process and procedures ensures that the risk impact of equipment OOS, while the plant is on-line, is appropriately evaluated prior to performing any maintenance activity or following an equipment failure or other internal or external event that impacts risk. Procedure AD7.DC6 provides guidance for managing the safety function, probabilistic risk, and plant trip risks, as required by 10 CFR 50.65(a)(4). The procedure addresses risk management practices in the maintenance planning phase and maintenance execution (real time) phase for Modes 1 through 4. Appropriate consideration is given to equipment unavailability, operational activities such as testing, and weather conditions. In general, on-line maintenance risk is reduced by:

- performing only those preventive and corrective maintenance actions on-line required to maintain the reliability of SSCs,

- reducing cumulative unavailability of safety-related and risk-significant SSCs by limiting the number of at-power maintenance outage windows per cycle per train/component,

- reducing the total number of SSCs OOS at the same time,

- reducing the risk of initiating plant transients (trips) that could challenge safety systems by implementing compensatory measures,

- avoiding higher risk combinations of OOS SSCs using PRA insights,

- maintaining defense-in-depth by avoiding combinations of OOS SSCs that are related to similar safety functions or that affect multiple safety functions, and

- scheduling train/bus windows to avoid removing equipment from different trains, simultaneously.

Licensee actions are taken and appropriate attention is given to configurations and situations commensurate with the level of risk as evaluated using DCPP Procedure AD7.DC6. This occurs both during planning and real time phases.

Risk is evaluated, managed, and documented for all activities or conditions, based on the current plant state:

- before any planned or emergent maintenance is to be performed,

- as soon as possible when an emergent plant condition is discovered, and

- as soon as possible when an external or internal event or condition is recognized.

Compensatory measures are implemented as necessary and, if the risk assessment reveals unacceptable risk, a course of action is determined to restore degraded or failed safety functions and reduce risk.

<u>Integrated Risk-Informed Assessment</u>

The proposed changes to TS Section 3.8.1, "AC Sources-Operating," that would allow the relaxation of the completion times for the required actions associated with the restoration of an inoperable DG have been evaluated by the licensee with a risk-informed approach. This approach demonstrates that the principles of risk-informed regulation are met for these proposed changes:

- the applicable regulatory requirements will continue to be met,

- adequate defense-in-depth will be maintained,

- sufficient safety margins will be maintained, and

- increases in CDF and LERF, as well as the magnitudes of ICCDP and ICLERP, are small and consistent with the staff’s Safety Goal Policy Statement and RG 1.174 and 1.177.

The limiting configuration is with DG 1-3 (2-3) unavailable. This is seen in the defense-in-depth analysis, as well as the CDF probabilistic results. Although the LERF PRA results indicate that DG 1-1 is more significant for that endstate, the DG OOS impact on LERF and containment performance is very small. The licensee’s PRA evaluation indicates that the risk increase is primarily due to the increases in risk from seismic sequences and, to a lesser extent, internal events.

Implementation and Monitoring Program

To ensure that the proposed relaxation of the DG completion time to 14 days does not degrade operational safety over time, should equipment not meet its performance criteria, an evaluation is required by the maintenance rule. The evaluation is to include prior related TS changes, including the present one, in its scope. The licensee will take appropriate corrective action, as required by the maintenance rule, including a change in the TS, if necessary.

With respect to the reliability and availability of the affected DGs under the licensee's maintenance rule program, if the pre-established reliability or availability performance criteria are not met for the DGs, they are considered for 10 CFR 50.65(a)(1) actions, requiring increased management attention and goal setting in order to restore DG performance (i.e., reliability and availability) to an acceptable level. The performance criteria are risk-informed and, therefore, are a means for the licensee to manage the overall plant risk profile. An accumulation of large core damage probabilities over time is precluded by the licensee's performance criteria. The actual OOS time for the DGs will be substantially reduced to ensure that the reliability and availability performance criteria are not exceeded.

The DG availability used by the licensee in the PRA analysis to calculate CDF values is consistent with the DG system maintenance rule goals, actual past performance of the DGs at the plant, and expected unavailability following implementation of the proposed relaxed DG completion time. The DG system maintenance rule performance criteria are consistent with the values used to calculate the risk metrics (i.e., the expected unavailability). All six DGs at DCPP are currently meeting their maintenance rule performance criteria.

DCPP Procedure MA1.ID17, "Maintenance Rule Monitoring Program," describes how the plant program complies with the maintenance rule. The procedure provides instructions for scoping, risk significance determination, performance criteria determination, monitoring, goal setting, periodic assessments, and maintenance rule [10 CFR 50.65(a)(4)] assessments.

As part of the DCPP maintenance rule program, the actual DG reliability and availability will be monitored and periodically evaluated. This licensee process will, in effect, assess the impact of the proposed relaxed DG completion time upon plant performance with respect to the maintenance rule goals. To ensure that the relaxed DG TS completion time does not degrade operational safety over time, the licensee's maintenance rule program will be used to identify and correct any adverse trends.

DCPP Procedure AD7.DC6 describes the tools and processes used for assessing and managing on-line risk. Included in this procedure is a process for assessing risk when the assessment tool is unavailable.

3.3.4 Probabilistic Risk Assessment Conclusion

The staff's acceptance of the licensee's proposed 14-day DG completion time is based on a risk-informed assessment. The licensee's risk assessment concluded that the increases in plant CDF and LERF, as well as the ICCDP and ICLERP magnitudes, are small and consistent with the staff's guidance as stated in RG 1.174 and 1.177. To ensure that the relaxation of the DG completion time does not degrade operational safety over time should the DGs not meet their performance criteria, an evaluation is required as part of the maintenance rule. This evaluation should include prior related TS changes in its scope and appropriate licensee corrective actions, including a change to the TS, if necessary.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the California State official was notified of the proposed issuance of the amendments. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration and there has been no public comment on such finding (68 FR 37581). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

6.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

Principal Contributors: O. Chopra
M. Wohl

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