APPENDIX E

APPLICANT'S ENVIRONMENTAL REPORT – OPERATING LICENSE RENEWAL STAGE

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ACRONYMS AND ABBREVIATIONS

AC	Alternating Current
ADT	Average Daily Traffic
AEC	Atomic Energy Commission
APCD	Air Pollution Control District
ARMP	Archaeological Resources Management Plan
ASW	Auxiliary Saltwater
Ave.	Avenue
BCC	Bird of Conservation Concern
BLM	Bureau of Land Management
Blvd.	Boulevard
BTA	Best Technology Available
BTU	British Thermal Unit
CAISO	California Independent System Operator
CCC	California Coastal Commission
CCMP	California Coastal Management Program
CCR	California Code of Regulations
CCRWQCB	Central Coast Regional Water Quality Control Board
CCW	Component Cooling Water
CDF	California Department of Forestry and Fire Protection
CDF&G	California Department of Fish and Game
CEC	California Energy Commission
CESA	California Endangered Species Act
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CHRIS	California Historical Resources Information System
CNPS	California Native Plant Society
CO	Carbon Monoxide

ACRONYMS AND ABBREVIATIONS (continued)

CPFV	Commercial Passenger Fishing Vessels
CPUC	California Public Utilities Commission
CSWRCB	California State Water Resources Control Board
CVCS	Chemical Volume and Control System
CWA	Clean Water Act
CWP	Circulating Water Pump(s)
DCM	Design Criteria Memorandum
DCPP	Diablo Canyon Power Plant
DDT	dichlorodiphenyltrichloroethane
DPS	Distinct Population Segment
Dr.	Drive
EDG	Emergency Diesel Generator
EFH	Essential Fish Habitat
EIA	Energy Information Administration
EMP	Ecological Monitoring Program
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ER	Environmental Report
ESA	Endangered Species Act
ESU	Evolutionary Significant Units
FES	Final Environmental Statement
FSAR	Final Safety Analysis Report Update
ft	Foot/Feet
GEIS	Generic Environmental Impact Statement
GHG	Greenhouse Gas

ACRONYMS AND ABBREVIATIONS (continued)

gpm	Gallons per Minute
GRS	Gaseous Radwaste System
GWh	Gigawatt Hour(s)
HAPC	Habitat Areas of Particular Concern
HEPA	High Efficiency Particulate Air
HISD	High-Intensity Short-Duration
I&E	Impingement and Entrainment
IPA	Integrated Plant Assessment
IR	Inspection Report
ISFSI	Independent Spent Fuel Storage Installation
Jct.	Junction
km	Kilometer(s)
kV	Kilovolt(s)
kWh	Kilowatt-hour
lb	Pound(s)
LLW	Low Level Waste
LOS	Level of Service
LPZ	Low Population Zone
LRS	Liquid Radwaste System
m	Meter(s)
mA	Milliamperes
MEMP	Marine Environmental Monitoring Program
mg	Milligram(s)
MLLW	Mean Lower Low Water

ACRONYMS AND ABBREVIATIONS (continued)

MLPA	Marine Life Protection Act
MM	Million
MRPS	Mobile Radwaste Processing System
MSA	Metropolitan Statistical Areas
MSL	Mean Sea Level
MWD/MTU	Megawatt-Days per Metric Ton of Uranium
MWe	Megawatt-electric
NA	Not Applicable
NAAQS	National Ambient Air Quality Standards
NEI	Nuclear Energy Institute
NEPA	National Environmental Protection Act
NESC	National Electric Safety Code
NMFS	National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
O_3	Ozone
OTC	Once-Through Cooling
pCi/L	Picocuries per Liter
PFMC	Pacific Fishery Management Council
PG&E	Pacific Gas and Electric Company
PM_x	Particulates having a diameter less than x microns
Pt.	Point
PBSMCA	Point Buchon State Marine Conservation Area

ACRONYMS AND ABBREVIATIONS (continued)

PBSMR	Point Buchon State Marine Reserve
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Assessment
PV	Photovoltaic
PWR	Pressurized Water Reactor
RCS	Reactor Coolant System
Rd.	Road
REMP	Radiological Environmental Monitoring Program
RMS	Root Mean Square
ROW	Rights-of-Way
Rte.	Route
RWMP	Receiving Water Monitoring Program
RWQCB	Regional Water Quality Control Board
SAMA	Severe Accident Mitigation Alternatives
SCCC	South-Central California Coast
SHPO	State Historic Preservation Officer
SLC	State Lands Commission
SLO	San Luis Obispo
SMITTR	Surveillance, Monitoring, Inspections, Testing, Trending, and Recordkeeping
So_x	Sulfur Oxide
spp.	Several Species
SRS	Solid Radwaste System
SRST	Spent Resin Storage Tank
St.	Street
SWRO	Seawater Reverse Osmosis
TEMP	Thermal Effects Monitoring Program

ACRONYMS AND ABBREVIATIONS (continued)

USDA	United States Department of Agriculture
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service
USGS	Unites States Geological Survey
WS	Withering Syndrome
YOY	Young of the Year
yr	Year

CHAPTER 1 - INTRODUCTION

1.1 PURPOSE OF AND NEED FOR PROPOSED ACTION

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants in accordance with the Atomic Energy Act of 1954, as amended, and NRC implementing regulations. Pacific Gas and Electric Company (PG&E) owns and operates the Diablo Canyon Power Plant (DCPP) Units 1 and 2 pursuant to NRC Operating Licenses DPR-80 (Docket No. 50-275) and DPR-82 (Docket No. 50-323), respectively. The Unit 1 license expires November 2, 2024 and the Unit 2 license expires August 26, 2025.

PG&E has prepared this environmental report in conjunction with its application to the NRC to renew the DCPP Units 1 and 2 operating licenses, in compliance with the following NRC regulations:

- Title 10, Energy, Code of Federal Regulations (CFR), Part 54, Requirements for Renewal of Operating License for Nuclear Power Plants, Section 54.23, Contents of Application-Environmental Information (10 CFR 54.23).

- Title 10, Energy, CFR, Part 51, Environmental Protection Requirements for Domestic Licensing and Related Regulatory Functions, Section 51.53, Post Construction Environmental Reports, Subsection 51.53(c), Operating License Renewal Stage [10 CFR 51.53(c)].

The NRC has defined the purpose for the proposed action, the renewal of operating licenses for nuclear power plants such as DCPP, as follows:

> "…The purpose and need for the proposed action (renewal of an operating license) is to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license to meet future system generating needs, as such needs may be determined by State, utility, and, where authorized, Federal (other than NRC) decision makers." (Reference 1)

The renewed operating licenses would allow for an additional 20 years of plant operations beyond the current DCPP licensed operating period of 40 years.

1.2 ENVIRONMENTAL REPORT SCOPE AND METHODOLOGY

NRC regulations for domestic licensing of nuclear power plants require environmental review of applications to renew operating licenses. NRC regulation 10 CFR 51.53(c) requires that an applicant for license renewal submit with its application a separate document entitled *Applicant's Environmental Report – Operating License Renewal Stage*. In determining what information to include in the DCPP Environmental Report, PG&E has relied on NRC regulations and the following support documents:

- NRC supplemental information in the *Federal Register* (References 1, 2, 3, and 7)
- *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (References 1 and 8)
- *Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses* (Reference 5)
- *Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response* (Reference 6)

PG&E has prepared Table 1.2-1 to verify conformance with regulatory requirements. Table 1.2-1 indicates where the environmental report responds to each requirement of 10 CFR 51.53(c). In addition, each responsive section of Chapters 3 and 4 are prefaced by pertinent regulatory language and applicable supporting document language.

1.3 DIABLO CANYON POWER PLANT LICENSEE AND OWNERSHIP

DCPP is owned and operated by Pacific Gas and Electric Company (PG&E). PG&E has owned and operated DCPP since issuance of the original Operating Licenses for both Units 1 and 2.

1.4 REFERENCES

1. NUREG-1437: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS), U.S. Nuclear Regulatory Commission, Volumes 1 and 2, Washington, DC, May 1996.

2. Environmental Review for Renewal of Nuclear Power Plant Operating Licenses, Federal Register, Vol. 61, No. 109, U.S. Nuclear Regulatory Commission, June 5, 1996.

3. Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Correction, Federal Register, Vol. 61, No. 147, U.S. Nuclear Regulatory Commission, July 30, 1996.

4. Environmental Review for Renewal of Nuclear Power Plant Operating Licenses, Federal Register, Vol. 61, No. 244, U.S. Nuclear Regulatory Commission, December 18, 1996.

5. NUREG-1440: Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses, U.S. Nuclear Regulatory Commission, Washington, DC, May 1996.

6. NUREG-1529: Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response, U.S. Nuclear Regulatory Commission, Volumes 1 and 2, Washington, DC, May 1996.

7. Changes to Requirements for Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Final Rules, Federal Register, Vol. 64, No. 171, U.S. Nuclear Regulatory Commission, September 3, 1999.

8. NUREG-1437: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS), Nuclear Regulatory Commission, Section 6.3, “Transportation” and Table 9-1, “Summary of findings on NEPA issues for license renewal of nuclear power plants,” Volume 1, Addendum 1, Washington, DC, August 1999.

TABLE 1.2-1

ENVIRONMENTAL REPORT RESPONSES TO LICENSE RENEWAL ENVIRONMENTAL REGULATORY REQUIREMENTS

Regulatory Requirement	**Responsive Environmental Report Section (s)**	
10 CFR 51.53(c)(1)	Entire Document	
10 CFR 51.53(c)(2), Sentences 1 and 2	3.0	Proposed Action
10 CFR 51.53(c)(2) Sentence 3	7.2.2	Environmental Impacts of Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(1)	4.0	Environmental Consequences of the Proposed Action and Mitigating Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	7.0	Alternatives to the Proposed Action
	8.0	Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	6.5	Short-Term Versus Long-Term Productivity of the Environment
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	6.4	Irreversible and Irretrievable Resource Commitments
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	4.0	Environmental Consequences of the Proposed Action and Mitigating Alternatives
	6.2	Mitigation
	7.2.2	Environmental Impacts of Alternatives
	8.0	Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	9.0	Status of Compliance
10 CFR 51.53(c)(2) and 10 CFR 51.45(e)	4.0	Environmental Consequences of the Proposed Action and Mitigating Alternatives
	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(3)(ii)(A)	4.1	Water Use Conflicts (Plants with Cooling Ponds or Cooling Towers Using Makeup Water from a Small River with Low Flow)
	4.6	Groundwater Use Conflicts (Plants Using Cooling Towers or Cooling Ponds and Withdrawing Makeup Water from a Small River)
10 CFR 51.53(c)(3)(ii)(B)	4.2	Entrainment of Fish and Shellfish in Early Life Stages
	4.3	Impingement of Fish and Shellfish
	4.4	Heat Shock
10 CFR 51.53(c)(3)(ii)(C)	4.5	Groundwater Use Conflicts (Plants Using >100gpm of Groundwater)
	4.7	Groundwater Use Conflicts (Plants Using Ranney Wells)
10 CFR 51.53(c)(3)(ii)(D)	4.8	Degradation of Groundwater Quality
10 CFR 51.53(c)(3)(ii)(E)	4.9	Impacts of Refurbishment on Terrestrial Resources
	4.10	Threatened or Endangered Species
10 CFR 51.53(c)(3)(ii)(F)	4.11	Air Quality During Refurbishment (Non-Attainment and Maintenance Areas)

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Regulatory Requirement	Responsive Environmental Report Section (s)	
10 CFR 51.53(c)(3)(ii)(G)	4.12	Microbiological Organisms
10 CFR 51.53(c)(3)(ii)(H)	4.13	Electric Shock from Transmission-Line-Induced Currents
10 CFR 51.53(c)(3)(ii)(I)	4.14	Housing Impacts
	4.15	Public Utilities: Public Water Supply Availability
	4.16	Education Impacts from Refurbishment
	4.17	Offsite Land Use
10 CFR 51.53(c)(3)(ii)(J)	4.18	Transportation
10 CFR 51.53(c)(3)(ii)(K)	4.19	Historic and Archaeological Resources
10 CFR 51.53(c)(3)(ii)(L)	4.20	Severe Accident Mitigation Alternatives
10 CFR 51.53(c)(3)(iii)	4.0	Environmental Consequences of the Proposed Action and Mitigating Alternatives
10 CFR 51.53(c)(3)(iv)	6.2	Mitigation
	5.0	Assessment of New and Significant Information
10 CFR 51, Appendix B, Table B-1, Footnote 6	2.6.2	Minority and Low-Income Populations

CHAPTER 2 - SITE AND ENVIRONMENTAL INTERFACES

2.1 LOCATION AND FEATURES

The Diablo Canyon Power Plant (DCPP) site is adjacent to the Pacific Ocean in San Luis Obispo County, California, and is approximately 12 miles west-southwest of the city of San Luis Obispo, the county seat and the nearest significant population center. The reactor for Unit 1 is located at latitude 35°12'44" North and longitude 120°51'14" West. The Universal Transverse Mercator (UTM) coordinates for zone 10 are 695,350 meters East and 3,898,450 meters North. The reactor for Unit 2 is located at latitude 35°12'41" North and longitude 120°51'13" West. The UTM coordinates are 695,380 meters East and 3,898,400 meters N. (Reference 2)

The residential community of Los Osos is approximately 8 miles north of the site. This community is located in a mountainous area adjacent to Montana de Oro State Park. The township of Avila Beach is located down the coast at a distance of approximately 7 miles southeast of the site. The city of Morro Bay is located up the coast approximately 11 miles northwest of the site (Reference 3). A number of other cities, as well as some unincorporated residential areas, exist along the coast and inland (Figure 2.1-1). However, these are at distances greater than 8 miles from the site. Only 11 inhabited residences are within 6 miles of the site (Reference 1). Figure 2.1-2 is a 6 mile vicinity map.

The DCPP site consists of approximately 750 acres of land located near the mouth of Diablo Creek, and a portion of the power plant site is bounded by the Pacific Ocean (Figure 2.1-3). Approximately 165 acres of the owner-controlled area are located north of Diablo Creek. The remaining 585 acres are located adjacent to and south of Diablo Creek. The entire acreage is owned by PG&E.

PG&E owns all coastal properties north of Diablo Creek, to the southerly boundary of Montana de Oro State Park and inland a distance of 0.5 to 1.75 miles. Similarly, PG&E owns all coastal properties south of Diablo Creek for approximately 8 miles and inland approximately 1.75 miles. Except for the DCPP site, all of the acreage north and south of DCPP is encumbered by two grazing licenses.

Section 3.1 provides a description of the plant and some of its key features.

2.2 AQUATIC ECOLOGY

DCPP uses a once-through cooling (OTC) water system that withdraws seawater from and discharges into the ocean via shoreline intake and discharge structures. A complete description of the circulating water system can be found in Section 3.1.2, *Cooling and Auxiliary Water Systems*.

2.2.1 MARINE ECOLOGY

Information presented in the following Marine Ecology sections was compiled from many reports generated from intensive monitoring programs of the marine environment, centered around Diablo Cove, which began in 1976. The program name most commonly used to refer to these studies is the Thermal Effects Monitoring Program (TEMP). The TEMP studies consist of monitoring of intertidal and subtidal algae, invertebrates and fish as well as several physical parameters. The frequency of the sampling each year changed from bi-monthly to quarterly in 1988. Changes in the scope-of-work resulted in various program name changes. Synonymous names for the TEMP are 316(a) Demonstration, Marine Environmental Monitoring Program (MEMP), Ecological Monitoring Program (EMP), and Receiving Water Monitoring Program (RWMP). A summary of the findings of the effects of the heated water discharge on marine communities in Diablo Cove and vicinity are presented in Section 4.4, *Heat Shock.*

Diablo Cove occupies the mid-portion of a rocky headland approximately 12 miles in lateral extent which tends approximately northwest to southeast and which is bounded to the north and south by extensive sand beaches. Point Buchon is the prominent feature of this shoreline which consists of wave exposed headlands alternating with semi-protected coves. Stable bedrock and variously sized boulders are the predominant substratum. Sand, as fine gravel and shell-debris, is uncommon in the intertidal areas, where it tends to be ephemeral, but becomes the predominant substrate with increasing distance and depth offshore. The near-shore intertidal and subtidal algae, invertebrates, and fishes in the area lying generally between Point Buchon to the north of DCPP and Point San Luis to the south of DCPP have been well studied (References 2, 13, 25, 26, 30, and 31) and are similar to the marine biological communities found in other areas of central California.

The near-shore marine environment is naturally divided into intertidal and subtidal zones. Maximum tidal range is approximately 9 ft and extends from 7 ft above mean lower low water (MLLW) to about 2 ft below MLLW. Within the study area used for the MEMPs, the subtidal zone reaches a maximum depth of approximately 60 ft below MLLW within 100 ft of shore. Based on physical characteristics, seven major habitats are represented:

<u>INTERTIDAL</u>

Rocky (semi-protected)	Bedrock and semi-stable boulder substrate that is relatively protected from the direct force of ocean swells. Generally of low aspect (slope) where organisms can occur both above and beneath moveable substrate.
Rocky (wave exposed)	Stable rocky headland with occasional very large boulders that is exposed to the direct force of ocean swell. Generally high aspect area where algae and invertebrates colonize higher elevations due to constant wave splash.
Tidepool	Entrapped pools of water that form in bedrock depressions during low tide. Can support species that are mainly found in upper subtidal zones. Uncommon within the study area.
Sand/Cobble	Beach habitat formed by sand/shell debris or small cobble. Highly unstable during periods of high swell, often covering and uncovering bedrock substrate. Uncommon within the study area.

<u>SUBTIDAL</u>

Bedrock/Boulder	Stable bedrock or boulder substrate ranging from shallow wave-exposed depths (0 to 7 m) to deeper, less wave-affected depths below 7 m. Bathymetric relief ranges from low boulder/flat bedrock to high relief pinnacle.
Sand/Shell debris	Sand/shell debris in small patches between rocks or forming extensive deposits. Can be highly unstable during periods of high swell, often covering and uncovering bedrock substrate.
Open water	Midwater zone from benthic substrate to sea surface.

The diverse assemblages of algae, invertebrates, and fishes within the study area are recognized as typical of the biogeographic transition zone that extends from Monterey Bay to San Diego Bay and includes both cool-temperate organisms typical of the northern Oregonian Province and warm-temperate organisms typical of the southern Californian Province (References 11, 15, 23, and 32). Within the study area, high biological diversity and high natural variation in the abundance and distribution of the plants and animals within the different near-shore zones results from variations in physical factors (for example, temperature, elevation, wave exposure, impact of severe winter storm waves and surge, open space, and substrate type) and biological factors (for example, grazing, predation, space competition, and recruitment episodes) (References 8, 9, 11, 20, and 33).

2.2.1.1 Species and Relative Abundance

Table 2.2-1 presents a list of nearly 800 taxa, the majority to species level, of algae, invertebrates, and fishes recorded from the near-shore intertidal and shallow subtidal zone of the DCPP study area. This list is not a complete inventory of all marine plant and animal species which may occur in the area because it includes only those taxa that were observed and recorded using the TEMP monitoring methods from 1976 through 2007. Although environmental monitoring was centered on Diablo Cove and became less intensive with increasing distance away from the Cove, this species list is representative of the flora and fauna of the near-shore marine environment for the entire rocky headland between Point Buchon to the north and Point San Luis to the south.

2.2.1.2 Species/Habitat Inventories

Algal Resources
The outer rocky coast of central California is one of the most diverse regions in the world for marine algae due to the presence of nutrient-rich upwelled waters and the variety of coastal habitats (Reference 4). Owing to their typically large size and dense concentrations, these algal species also serve as important habitat and food resources for a variety of aquatic animals. For example, kelp canopies provide important habitat for fishes, particularly juveniles, which closely associate with the kelp fronds for protection from predation. The DCPP study area shares many species and habitat features with other central California areas described by Abbott and Hollenberg (Reference 4). Sparling (Reference 35) developed a list of over 400 taxa of marine algae in San Luis Obispo County, including the DCPP study area. Approximately 225 species and higher taxa categories of algae have been identified in the TEMP sampling (Table 2.2-1). None of the algal taxa is unique to this area (endemic) and none is federally or state listed as a rare or endangered species.

Intertidal Algae. Approximately 176 algal taxa have been identified in the intertidal zone during TEMP studies of the near-shore marine environment (Reference 36) with 60 of those being unique to the intertidal zone (Table 2.2-1). The abundance and types of algae increase from the high intertidal to the low intertidal zones. Most intertidal algal species are restricted to specific elevation ranges and occur in bands along the shoreline. The upper vertical distribution for most species is largely determined by their ability to withstand desiccation, but shading, competition for space, and grazing are important factors as well. The high intertidal zone is only occasionally wetted by wave splash and is sparsely covered by algae such as the red alga *Bangia* spp., and the green alga *Enteromorpha* spp. The barren appearance of the splash zone disappears lower in the intertidal zone (+4 ft MLLW) as algal cover becomes more conspicuous with scattered clumps of rockweeds (*Fucus* and *Silvetia)* and the turfy red alga *Endocladia muricata*. A dominant species in the mid- to low intertidal zone is the iridescent red alga *Mazzaella flaccida*. Other abundant red algae include hollow branch seaweed (*Gastroclonium subarticulatum*), grapestone seaweed (*Mastocarpus papillatus*), and Christmas tree seaweed (*Chondracanthus canaliculatus*). Surfgrass (*Phyllospadix* spp.), a flowering plant, is the dominant plant in the transition zone between the low intertidal and the shallow-subtidal. Surfgrass is listed by the California Department of Fish and Game as a species of special concern.

Subtidal Algae. Approximately 163 algal taxa have been identified in the subtidal zone during TEMP studies with 47 of those being unique to the subtidal zone (Table 2.2-1). The subtidal algal assemblage is spatially dominated by various species of kelp. Bull kelp (*Nereocystis luetkeana*) is a common surface canopy-forming kelp along the coast in the area of DCPP. Giant kelp (*Macrocystis pyrifera*) occurs with bull kelp in semi-exposed areas, but tends to be more abundant in calmer water. A third surface canopy-forming kelp species, *Cystoseira osmundacea*, also occurs with these two kelps, generally in areas shallower than about 30 ft. The canopies of all three species develop in the spring and become thickest during summer through fall. Tree kelps (*Pterygophora californica* and *Laminaria setchellii*) do not reach the surface but are perennial species that provide subcanopy structure less than 3 ft off the bottom.

Below the kelp canopies are the lower growing foliose, branched, filamentous, and crustose understory species consisting mainly of red and brown algae. Among the red algae, the more common and abundant taxa are articulated coralline algae (*Calliarthron/Bossiella/Serraticardia* complex), and other foliose and branching red algae (*Cryptopleura* spp., *Pikea* spp., *Farlowia* spp., *Callophyllis* spp., *Mastocarpus* spp., and *Rhodymenia* spp.). Common brown algae include *Dictyoneurum californicum* and *Desmarestia* spp.

Invertebrate Resources
Similar to the algal resources, the invertebrate communities that inhabit the intertidal shoreline and shallow subtidal along the central coast of California are very diverse (References 10, 11, and 32). The DCPP TEMP monitoring program has identified nearly 440 invertebrate taxa, most to species level, from the near-shore marine environment of the DCPP study area (References 37, 38, 39, and 40) (Table 2.2-1). This coast is part of a faunal transition zone with affinities to areas both north and south of Point Conception. None of the marine invertebrate taxa are endemic, and only one found in the vicinity is federally or state listed as rare or endangered. Abalone, including the locally common and formerly abundant red and black abalone (*Haliotis rufescens* and *H. cracherodii*, respectively), have been state-protected from commercial and recreational harvesting in this area and elsewhere since 1997. The black abalone was subsequently added to the federal endangered species list in 2009.

Intertidal Invertebrates. TEMP studies from 1976 through 2007 have identified over 350 invertebrate taxa from the intertidal zone of the DCPP study area. The diversity of invertebrate species increases from high to low elevations. In the splash zone, periwinkle snails (*Alia* spp.) are found in rock crevices while the black turban snail (*Chlorostoma funebralis*) and lined shore crab (*Pachygrapsus crassipes*) occur in the shade of boulders. Occasionally a high intertidal tidepool will contain species more commonly found in lower elevation habitats. The barren appearance of the splash zone disappears lower in the intertidal as algal cover becomes more conspicuous. This truly intertidal area (the highest regularly submerged) is inhabited by numerous species of limpets (*Lottia* spp.), the acorn barnacle (*Chthamalus fissus)*, patches of aggregating sea anemone (*Anthopleura elegantissima*), and occasional patches of California mussels (*Mytilus californianus*). At lower intertidal levels, beneath the foliose blades of the algae, abundant organisms include hermit crabs (*Pagurus* spp.*)*, turban snails (*Chlorostoma* spp.), tube-forming polychaete worms (*Phragmatopoma californica* and *Pista* spp.*)*, and encrusting forms of various bryozoans, sponges, and tunicates. Common invertebrate predators in the intertidal zone include seastars (*Pisaster ochraceus* and *Leptasterias* spp.), snails (*Acanthinucella spp.*, *Aptyxis luteopictus, Ocenebrina* spp.), rock crabs (*Cancer* spp.), and octopus (*Octopus* spp.). Intertidal invertebrate herbivores include purple sea urchins (*Strongylocentrotus purpuratus*) and kelp crabs (*Pugettia* spp.).

Subtidal Invertebrates. Over 330 invertebrate taxa have been identified occupying the subtidal zone shallower than 55-ft in the vicinity of the DCPP (References 37, 38, 39, and 40). The distribution and abundance of these organisms are controlled by various biotic and abiotic factors which cause their populations to fluctuate over time. Gotshall et al. (Reference 13) and Tenera (References 37, 38, 39, and 40) showed that numerically important invertebrate herbivores include red and purple urchins (*Strongylocentrotus franciscanus* and S. *purpuratus*, respectively), brown turban snails (*Chlorostoma brunnea)*, Monterey turban snails (*C. montereyi*), top snails (*Pomaulax gibberosa* and *P. undosa*), red abalone (*Haliotis rufescens*), giant gumboot chitons (*Cryptochiton stelleri)*, and many smaller species of invertebrates. Invertebrate predators include sunflower seastars (*Pycnopodia helianthoides*), giant spined seastars (*Pisaster giganteus*), short-spined seastars *(Pisaster brevispinus*), rock crab (*Cancer antennarius*), *Kellet's whelk* (*Kelletia kelletii*), octopus (*Octopus* spp*.)*, and a variety of smaller predatory seastars, gastropods, and crustaceans. The common deposit feeders, scavengers, and filter feeders include bat stars (*Patiria miniata*), anemones (*Anthopleura xanthogrammica*, *A. sola* and *Epiactis prolifera*), cup corals (*Balanophyllia elegans*), sponges (*Tethya californiana* and other encrusting forms), tunicates (*Styela montereyensis* and the encrusting colonial/social tunicates), tube snails (*Serpulorbis squamigerus*) and brittle stars (*Ophiothrix spiculata*). Invertebrate grazers include the nudibranchs *Phidiana hiltoni* and *Doriopsilla albopunctata*.

Fish Resources

Fish resources along the central California coast are rich and diverse, in part due to highly productive upwelling in the region and the diversity of habitats. Over 400 taxa of near-shore fishes (in less than depths of 400 ft) have been documented in California, and most of these are known to occur in central California (Reference 21). Habitat structure and fish assemblages along the DCPP coastline are similar to other rocky near-shore areas in central California. The near-shore fish fauna in the DCPP area is characterized by taxa with mostly northern affinities, but some with southern affinities. Approximately 120 taxa have been observed within the study area in conjunction with the TEMP monitoring studies (References 37, 38, 39, and 40) (Table 2.2-1). None of the taxa in the vicinity of DCPP are considered to be endemic and none are federally or state listed as rare or endangered.

Intertidal Fishes. Studies on the intertidal fishes of the DCPP study area identified a total of 37 fish taxa (References 37, 38, 39, and 40), 15 of which were only found in the intertidal zone and the remainder occurring in both the intertidal and shallow subtidal zone. The assemblage is similar to that described from other central California rocky coast intertidal habitats (Reference 42). Several intertidal fishes are commonly associated with various algal species which they either use directly as a food source or glean other foods from their surfaces (Reference 17).

Common fishes found in the intertidal zone are black and rock pricklebacks (*Xiphister atropurpureus* and *X. mucosus)*, high cockscomb (*Anoplarchus purpurescens*), sculpins (*Artedius* spp. and *Oligocottus* spp.), clingfish (*Gobiesox maeandricus*), juvenile monkeyface eel (*Cebidichthys violaceus*), rockweed gunnel (*Apodichthys fucorum*), and penpoint gunnel (*A. flavidus*). Over 90 percent of the individual fish in the intertidal zone of the project area are small eel-like fishes of the family Stichaeidae (pricklebacks) and Pholidae (gunnels).

Subtidal Fishes. Over 100 species of fishes have been identified in the near-shore areas (less than depths of 45 ft) surveyed in the TEMP subtidal fish observation studies. Some of the common adults and juveniles belong to the family of rockfishes (Scorpaenidae), surfperches (Embiotocidae), sculpins (Cottidae), wrasses (Labridae), and greenlings (Hexagrammidae). Other schooling fish which can be very common at certain times of the year include northern anchovy (*Engraulis mordax*), Pacific sardine (*Sardinops sagax)*, jack mackerel (*Trachurus symmetricus*) and tubesnout (*Aulorhynchus flavidus*). Species identified from the TEMP studies are presented in Table 2.2-1.

Because of the proximity of Diablo Cove to Point Conception (the northern boundary of the southern California bight), fishes with more southern affinities are occasionally found in the area, especially during warm-water years. Sheephead (*Semicossyphus pulcher*), kelp bass (*Paralabrax clathratus*), white seabass (*Atractoscion nobilis*), giant kelpfish (*Heterostichus rostratus*), and garibaldi (*Hypsypops rubicundus*), are among the fishes that can either migrate as adults or be transported from south to north as larvae. These fishes, however, can establish small reproductive populations in the DCPP area.

Marine Mammal Resources

At least 21 species of cetaceans (whales, dolphins, and porpoises) have been reported in central California but few are common to the DCPP vicinity. Gray whale (*Eschrichtius robustus*), humpback whale (*Megaptera novaeangliae*), minke whale (*Balaenoptera acutorostrata*), killer whale (*Orcinus orca*), and common bottlenose dolphin (*Tursiops truncatus)* have been observed in the vicinity of DCPP.

The four common residential marine mammals in the DCPP vicinity are California sea lion (*Zalophus californianus*), harbor seal (*Phoca vitulina*), northern elephant seal (*Mirounga angostrirostris*), and southern sea otter (*Enhydra lutris*).

Seasonally, several hundred sea lions "haulout" (seek resting habitat on dry land) on Lion Rock, Pup Rock, and Pecho Rock. Diablo Rock and the Intake Cove breakwater are small in comparison and typically provide marginal haulout habitat for sea lions. Local populations reach their peak in the fall as the breeding populations disperse from the Channel Islands in the Southern California Bight. Sea lions are wide ranging and may be found along the entire central California coastline. Northern (Steller) sea lions (*Eumetopias jubatus)* are rare in the DCPP study area but have been observed historically on Lion Rock (Reference 7).

Harbor seals are common, year-round residents in the area of DCPP. Aerial censuses along the coastline between Morro Bay and Point San Luis by California Department of Fish and Game recorded approximately 2,000 seals in 1991 (Reference 14). Harbor seals are observed to breed and pup in the area including the intake cove of DCPP. The many haulout sites used by harbor seals between Point Buchon and Point San Luis are usually flat rock benches or rocks lying on headlands or just offshore or small pocket beaches backed by high cliffs.

A small seasonal aggregation of approximately 50 northern elephant seals began using the Intake Cove in 1986 as a resting and molting site (Reference 18). The haulout site was never used for breeding or pupping, and was last used by elephant seals in 1992. Migrating elephant seals pass through the DCPP area and are commonly observed in the Intake Cove at DCPP, but the nearest concentration of seals (over 3,000) seasonally occupies beaches in the vicinity of Point Piedras Blancas, approximately 69 km (43 mi) north of DCPP.

Through 2009, there has not been a known or recorded incident of a marine mammal injury or fatality caused by power plant operations.

Sea Turtle Resources

The species of threatened or endangered sea turtles that may occur in the vicinity of the DCPP facility include the green sea turtle (*Chelonia mydas*), leatherback sea turtle (*Dermochelys coriacea*), loggerhead sea turtle (*Caretta caretta*), and olive Ridley sea turtle (*Lepidochelys olivacea*).

Through 2009, there have been 9 incidences of power plant intake structure impingement/trapping of sea turtles (1-1994, 2-1997, 2-1999, 1-2000, 1-2001, 1-2007, and 1-2009). All incidences involved the green sea turtle (*Chelonia mydas*). The turtles were discovered by plant operators during routine surveillance on the ocean surface inside the concrete intake curtain wall in front of the debris bar racks. All incidences resulted in live capture and successful release of the turtles to the open ocean. No injuries or other obvious detrimental effects to the turtles were noted as a result of these events.

In 2006, the National Oceanic and Atmospheric Administration developed a biological opinion based on the best available scientific and commercial information that concluded the continued operation of the DCPP was not likely to jeopardize endangered or threatened sea turtle species (Reference 24). This biological opinion was developed in consultation with the NRC. DCPP received a sea turtle incidental take statement in conjunction with the biological opinion.

2.2.1.3 Commercial and Recreationally Important Species

A listing of the commercial and recreationally important marine species known to occur or potentially occurring in near-shore habitats within the vicinity of DCPP is presented in Table 2.2-2. Leet et al. (Reference 19) reviewed the status of California's living marine resources by examining long-term landings data for approximately 120 finfish and shellfish species.

Commercial fishery data for San Luis Obispo County indicate that the highest biomass came from cabezon (*Scorpanichthys marmoratus*) between 1981 and 2006. The biomass of the top ten taxa came from cabezon (*S. marmoratus*), swordfish (*Xiphias gladius*), Chinook salmon (*Oncorhynchus tshawytscha*), Blackgill rockfish (*Sebastes melanostomus*), English sole (*Parophrys vetulus*), California halibut (*Paralichthys californicus*), lingcod (*Ophiodon elongatus*), Chilipepper (*Sebastes goodie*), petrale sole (*Eopsetta jordani*), and the common thresher shark (*Alopias vulpinus*), respectively. Cabezon biomass totaled 9.5 million lbs. The other taxa listed above cumulatively weighed more than 7.75 million lbs for the 26 years of available data.

Data from the National Oceanic and Atmospheric Administration (NOAA) from the year 2000 suggest that of the 123,441 landings reported in Avila Beach and Port San Luis, rockfish (*Sebastes* spp.) accounted for 93.9 percent of the total. Albacore tuna (*Thunnus alalunga*) landings accounted for 4.6 percent of the total.

Recreational fishing activities in California are monitored by the California Department of Fish and Game through the California Recreational Fisheries Survey program. The program surveys recreational anglers and divers using a variety of angling modes including: commercial passenger fishing vessels (CPFV), private vessels (skiffs, kayaks, etc.), beaches and banks, and manmade structures (jetties, piers, and breakwaters) (Reference 6). The primary target species or species groups for CPFVs and private vessels are king salmon, rockfishes/lingcod/cabezon/kelp greenling, California halibut, sanddabs, and albacore (Reference 6). Anglers from beaches and banks typically target surfperches, jacksmelt, and several near-shore rockfishes, and anglers from manmade structures target Pacific sardine, northern anchovy, jacksmelt, surfperches, white croaker, and several near-shore rockfishes. As a group, rockfish dominate the CPFV and private vessel catch and rockfish landed at Port San Luis/Avila and Morro Bay accounted for over 94 percent of the catch from 1996-1999. Thompson (Reference 41) has estimated that private boats and the CPFV fleet land an equal number of rockfish. Combined they account for 20 percent of the rockfish caught offshore California.

A security zone established in 2002 prohibits unauthorized entry into marine waters within a one nautical mile radius of the DCPP for any purpose including commercial and recreational fishing. Commercial and recreational fishing is also prohibited in the Point Buchon State Marine Reserve (PBSMR), which was established in 2007 pursuant to the 1999 Marine Life Protection Act (MLPA) and extends north from the security zone boundary approximately three miles to Point Buchon. The Point Buchon State Marine Conservation Area (PBSMCA), also established under the MLPA, adjoins the western boundary of the PBSMR and extends westward to the 3 nautical mile offshore boundary where state jurisdiction ends. Take of all living marine resources is prohibited in the PBSMCA with the exception of the commercial and recreational take of salmon and albacore.

2.2.2 FRESHWATER ECOLOGY

DCPP is located on a narrow, gently sloping coastal terrace situated between the Irish Hills to the east and the Pacific Ocean to the west. A coastal climate prevails in the region with long, dry, warm summers and short, wet, mild winters. Fog is common in the summer months and rainfall is highly variable within and between winter seasons. The climate and steep topography and soils of the surrounding land result in a limited abundance of aquatic habitat on PG&E-owned lands.

Freshwater aquatic habitat is present within four primary drainages on PG&E-owned lands and four man-made ponds. The primary drainages to the north of DCPP are Coon Creek and Diablo Creek (Figure 2.2-1), which flow in a westerly direction into the Pacific Ocean. Coon Creek is a perennial or intermittent stream located at the northern boundary of PG&E-owned lands and drains a watershed of 5,500 acres. Diablo Creek is the next largest primary drainage with a watershed of 3,190 acres. Surface flow in Diablo Creek is perennial in the lower reaches and intermittent in the upper reaches during the summer and fall (Reference 12). Diablo Creek passes through the DCPP site vicinity beneath the 230 kV and 500 kV switchyards in a large culvert before returning to the natural creek approximately 0.3 miles east of the Pacific Ocean.

To the south of the plant are Irish Canyon Creek and Pecho Creek, which flow in a southerly direction into the Pacific Ocean and drain a combined watershed area of less than 4000 acres. Both creeks have intermittent surface water flow during the dry months. The four small man-made ponds (less than one-surface-acre each) on PG&E-owned lands were developed to provide irrigation water for row crops and drinking water for cattle. Three of the ponds are located at the outlet of small canyons south of DCPP and one is located on the coastal terrace to the north.

DCPP currently uses seawater for once-through cooling. In the past, several wells and diversions along Diablo Creek were used to supply daily makeup water for the plant and water for other operational needs. Currently, naturally occurring freshwater for plant use can only be provided by a single permitted well (Deep Well #2) located adjacent to Diablo Creek. The well is intended only for infrequent use as a supplemental freshwater resource. The other drainages and ponds on the site are isolated from the facility and not impacted by DCPP operations.

Information presented in the following Freshwater Ecology sections was compiled from field surveys conducted between 1986 and 2008 by PG&E staff biologists and various biological consulting firms. Vertebrate species investigations of Diablo Creek were conducted in 1986 and 1990 and in other aquatic habitat on PG&E-owned lands from 1990 through 1993. Fishery investigations were conducted more recently on Coon Creek in conjunction with a steelhead habitat improvement project (Reference 43), and in 2006 as part of a comprehensive inventory of natural resources prepared in support of the Point Buchon Trail public access program (Reference 44).

2.2.2.1 Species and Relative Abundance

The results of past fisheries investigations indicate that Diablo Creek and Coon Creek are the only streams on the PG&E-owned lands that support fish populations. Fish sampling efforts on both streams documented the presence of self-sustaining populations of rainbow trout/steelhead (*Oncorhynchus mykiss [O.mykiss]*), but no other fish species have been observed. The fishes observed in Coon Creek belong to the South-Central California Coast steelhead (SCCC) Distinct Population Segment (DPS) and are federally listed as threatened. There is some question as to whether the fishes observed in Diablo Creek are SCCC steelhead or are resident *O.mykiss.* A barrier at the mouth of Diablo Creek is reported to be potentially impassible to the upstream migrating steelhead, making upstream reaches inaccessible for spawning (Reference 28). Consequently, the *O.mykiss* in Diablo Creek may meet the DPS Policy criteria for marked separation of population groups (physically, physiologically, ecologically, and behaviorally) and therefore would not be included in the South-Central California Coast steelhead DPS listing.

The other drainages on the property are small ephemeral streams located south of DCPP including the two primary drainages, Irish Canyon Creek, and Pecho Creek. Stream surveys conducted on PG&E-owned lands from 1992 through 1993 found no fish present in any of the streams south of the power plant.

Ponds to the south of the power plant were surveyed for presence of fish in 1990 (Reference 22), and again in 1993 (Reference 12), and none were found. It has been reported that the pond located north of the power plant was planted with several species of fish including steelhead from Coon Creek, by a local caretaker; date unknown (Reference 12). When sampled in 1990, three-spined stickleback (*Gasterosteus aculeatus*; not the federally listed subspecies *G. a. williamsoni)*, and mosquito fish (*Gambusia affinis*) were found in the pond, while two specimens of larger fish were not identified. The larger fish may have been either steelhead, black bullheads (*Ictalurus melas*), or largemouth bass (*Micropterus salmoides*) (Reference 12).

In addition to fisheries investigations, protocol surveys for the federally threatened California red-legged frog (*Rana aurora draytonii*) were conducted in August 1999, within and adjacent to Diablo Creek, and again in 2002. The results of both surveys were negative. Southwestern pond turtle (*Actinemys marmorata pallida*) surveys were also performed on Diablo Creek in 2002 with negative results. Surveys for California red-legged frogs, southwestern pond turtles, and two-striped garter snakes (*Thamnophis hammondii*) were also conducted in Coon Creek and Tom's Pond during 2005 and 2007 for the DCPP North Ranch Access Monitoring project (Reference 27). Although suitable habitat for all three special status species was present, none were detected (Reference 27).

2.2.2.2 Species/Habitat Inventories

Watershed Descriptions
An ecological profile of Diablo Creek was prepared by PG&E in 1991 (Reference 12). The ecology of Coon Creek is believed to be similar to that of the natural flow reaches of Diablo Creek. A description of the ecology of Diablo Creek, taken from Reference 12 is presented below.

Geology and Soils
The Diablo Creek watershed is similar to many coastal canyons of the western San Luis Mountains, consisting of a narrow gently sloping coastal terrace with sharply rising adjacent uplands. Underlying the watershed is the Miocene Monterey formation, consisting of resistant hard siliceous shale and interbedded chert (Reference 45). The color is variable, generally white and brown to gray and reddish-brown on fresh surfaces, weathering to chalky white. The formation shows evidence of many sedimentary layers with great total depth. Individual beds are brittle and fracture easily, with thickness varying between 0.5 and 6 inches. Evidence of bedding is common from channel invert to ridge tops.

The length of the watershed is about four times its average width. Hillside slopes of 30 to 75 percent are common throughout. Upland soils on the steeper slopes are thin, with a shallow depth to parent material. They are typical of the loose, rocky, coarse-textured, acidic Santa Lucia soils, and are characterized by low fertility and low water retention capabilities.

Channel Morphology
The total channel length is about 5.1 miles from watershed ridge crest to ocean outfall. Surface water flow is intermittent seasonally over the lower 2 miles of stream channel. This may be true, as well, for the upper 3 miles of Diablo Creek. Detailed field surveys in this part of the watershed have not been undertaken. The banks of Diablo Creek in the areas inspected are composed of multiple strata of alluvial materials of varying thickness and composition, deposited over geologic time. At least one of the layers is composed of very porous cobble and gravel materials. In the lower watershed, channel banks are generally at a slope of 1:1 or steeper, with depths of 3 to 8 ft. Natural banks appear to be generally stable on a long-term basis, with mature oak trees and other

vegetation growing down the channel bank. The channel slope, averaging about 5 percent throughout much of the watershed, is generally steep enough to prevent significant sediment or bed load deposition.

Extensive local geologic investigations have been made in conjunction with switchyard fill design. Results reported from test borings indicate that subsurface alluvial materials exposed in the channel invert may be as deep as 30 ft, extending up to 200 ft laterally from the channel. This finding is consistent with observed surface dewatering of significant segments of the Diablo Creek channel, except in periods of high flow. Subsurface water available in the extensive alluvial beds may be partially recovered in the wells at the lower end of the watershed.

DCPP began diverting water from three points on Diablo Creek, hereafter referred to as Diversion Points 1, 2, and 3, in 1968. Records maintained for purposes of necessary annual filings with the California State Water Resources Control Board show that Diversion Point 2 served as a supplemental or backup source to Diversion Point 1, and both contributed raw water to the power plant makeup water system. Diversion Point 3 was a water source for dust control during early construction of DCPP (1968-1973). Figure 2.2-2 includes the locations of Diversion Points 1, 2, and 3. As indicated in Section 3.1.2, DCPP no longer withdraws surface water from Diablo Creek.

A natural waterfall (hereafter referred to as Diablo Falls) exists in the channel about 2 miles upstream of Diversion Point 1, or 3 miles above the ocean outfall. Bedrock conditions at Diversion Point 1 are believed to force migrating groundwater to the surface, where total flow may be measured. Flow over the waterfall was estimated at 300 gpm in early March 1991, about two to three times that observed on the same date at Diversion Point 1.

The lower 3 miles of creek channel is composed of deep and extremely porous cobbles and gravel of native materials. Such bed conditions result in subsurface flow of all or part of the total flow. This condition is influenced by the magnitude of flow and location in the watershed channel. Late season flow downstream of the waterfall is entirely subsurface for more than 1 mile. About one-third to one-half of the late season subsurface flow was observed to return to the surface at Diversion Point 1, where it was captured and used for power plant purposes prior to 2007. Some of the subsurface flow may be captured by the remaining freshwater well located immediately upstream of the 500 kV switchyard (Figure 2.2-2).

Erosion Potential

A uniform and healthy ground cover is desirable for maximizing water retention while minimizing erosion and sediment transport from steep hillside areas. A healthy plant community provides mechanical protection from rainfall, sheet, and rill erosion. The plant canopy provides surface protection from the thermal and convective effects of the air mass, helping to conserve and retain moisture. Organic matter also helps to improve soil infiltration and moisture retention. Ground cover in the watershed consists of a mosaic of plant communities in generally good hydrologic condition. Vegetative cover is poorest where rocky outcrops or road cuts prevent satisfactory soil depth for plant establishment. Sediment loading and erosion potential are maximized in areas where runoff flow is concentrated by road cuts, culverts, and equipment trails. Fuel load management areas where mechanical and hand clearing have recently occurred are at higher risk for runoff and erosion than similar untreated areas. A catastrophic event such as a large-scale range fire would be expected to change hydrologic conditions by increasing peak runoff flows and associated sedimentation, while reducing the magnitude of late season return flows. Tower access roads in the lower watershed may contribute to sedimentation. Exposed cut and fill slopes lacking vegetation, and unprotected drainage features tend to concentrate runoff flows.

Hydrology

Peak runoff flows for different return periods were estimated using a Soil Conservation Service hydrologic model. Precipitation frequency data and watershed area measurements taken from the Port San Luis 7.5 minute USGS Topographic Quad were used to obtain the model outputs. These modeled values are statistical estimates of short-term peak runoff flows, which differ from the average residual flows. Rather than being precise, estimates of this kind are order-of-magnitude in nature. The 3,200 acre watershed is drained by a 5.1-mile main channel with numerous ephemeral tributaries. Runoff is rapid because of steep slopes and the presence of shallow soils with low water-holding capacity in upland areas. Modeled short-duration peak flows at the watershed outlet for a 100-year storm (1 percent annual probability of occurrence) are estimated at between 500 and 2,500 cfs (0.22 to 1.12 million gpm; 1 cfs equals 450 gpm), and depend on assumptions made about upland soil and vegetation conditions. These extreme values are consistent with the 10 ft diameter culvert and emergency overflow channel designs used at the switchyard complex. Peak watershed runoff measured by PG&E staff to date is a flow of about 2,600 gpm after a 24-hour period with 5 inches of rainfall in March 1980. Observed peak flows are lower than expected for a watershed of this size and steepness. This likely is a result of the highly porous nature of the watershed.

Maximum and minimum flows in Diablo Creek are highly variable. Average flows tend to be nearer the minimum flow values. Maximum flows reflect short-term conditions associated with storm events. Usually within 1 or 2 days following a storm, flows return to normal. Flows during the wet season (October through April) vary daily and monthly. Dry season flows are sustained by groundwater seepage and are more consistent from day to day, gradually tapering off over time.

To date, the highest recorded flow (2,596 gpm) occurred in March 1980, when in one day, 5 inches of rainfall were recorded. Average maximum flows during the wet season range between 500 and 1,000 gpm. The lowest recorded flow to date (32 gpm) occurred in October 1968. During the mid-1970s drought, minimum flows (average of mean monthly data) were about 200 gpm. Applying this statistic to flow data for the 1970s 5-year drought shows minimum flows averaging about 65 gpm, or 32 percent of the minimum flows recorded during the last significant statewide drought.

Aquatic Biology
Thirty-three invertebrate taxa and one fish (*O.mykiss*) were identified in the 1986 aquatic survey of Diablo Creek. *O.mykiss* is the only fish species known to occur in Diablo Creek, and they are present in all four stream sections. They occur in upstream areas where surface water flow is present throughout the year. They also occur in pools that remain watered when adjacent stream reaches are reduced to subsurface flows.

The results of fish sampling in Diablo Creek in 1986 and 1990 also showed relatively low numbers of *O.mykiss* with a high ratio of juvenile/adult fishes (greater than 4 inches) to young-of-the-year (YOY) fishes (less than 4 inches). This suggests either low reproductive success or high juvenile mortality. The portion of the creek above Diversion Point 1 (upper reaches starting about one-half mile above the Independent Spent Fuel Storage Installation site) supported higher numbers of *O.mykiss* than were found below the diversion. This is primarily due to the better overall habitat conditions above the diversion. Because of the intermittent nature of surface flows in Diablo Creek, resident *O. mykiss* tend to concentrate in still pools or where flowing water is present year-round.

Water Quality
Water quality is further monitored according to conditions specified in NPDES Permit CA0003751. Water from several yard storm discharge points is sampled annually for grease and oil contaminants. Results of this monitoring are reported to the Central Coast Regional Water Quality Control Board (CCRWQCB). A report titled Potential Effects of Storm Water Discharges on Diablo Creek (Reference 46) provides analysis of 14 water quality parameters and pollutants associated with yard and storm drain runoff samples. Other pollutants were also identified that could potentially enter the stream as a result of accidental spills. These data were then compared with published toxicity levels for aquatic organisms. The report concluded that pollutant levels in the sampled discharges were below concentrations known to affect rainbow trout, and the potential of storm and yard water runoff to cause adverse effects in Diablo Creek was mitigated by a short residence time and rapid dilution under storm flow conditions. The study was conducted during a relatively high runoff year placing greater emphasis on wet season than dry season flows. The presence of *O.mykiss* in Diablo Creek is an indication of good overall water quality, as the species is known to be sensitive to changes in a variety of water quality parameters.

Riparian Vegetation
Riparian vegetation forms a narrow band along both sides of Diablo Creek in all open channel sections. It is characterized by the least amount of prior disturbance upstream from Diversion Point 3, reaching its best expression in the vicinity of Diablo Falls. This habitat type is dominated by extensive stands of red willow (*Salix laevigata*), big-leaf maple (*Acer macrophyllum*), elderberry (*Sambucus mexicana*), wild cucumber (*Marah fabaceus*), poison hemlock (*Conium maculatum*), nettle (*Urtica holosericea*), and rush (*Juncus balticus*). Although this habitat type is the least abundant in the watershed, it is

characterized by a high index of floristic diversity and provides important habitat elements for fish and wildlife.

2.2.2.3 Commercial and Recreationally Important Species

No commercially important species are known to occur in freshwater habitats within the PG&E-owned lands. Steelhead are the only recreationally important species occurring on PG&E-owned lands; however, recreational steelhead fishing has been curtailed since the federal listing of the South-central California Coast DPS steelhead in 1997 as a threatened species (62 FR 43937). The waters of Coon Creek are listed under California freshwater sportfishing regulations as closed to steelhead fishing throughout the year. Regulations also prohibit steelhead fishing in Diablo Creek and other drainages on the PG&E-owned lands surrounding DCPP. Additionally, public access is restricted on the site and the recreational use of streams is not allowed.

2.3 GROUNDWATER RESOURCES

Groundwater at the DCPP site is limited to the streambed of Diablo Creek within the geographically isolated Diablo Canyon. No significant groundwater has been encountered outside of the stream bed gravels. Three small springs were encountered during excavation for plant construction; two of these were wet spots and the third had a flow of less than 30 gpm. The water was analyzed and found to be very hard (1050 mg/1 $CaCO_3$ and high in dissolved residue (2148 mg/1). Groundwater and domestic water supplies are not affected by the operation of the plant (Reference 3). Use of onsite groundwater is limited to supplementing the supply of the Raw Water Storage Reservoirs which feed the emergency firewater, plant site domestic water, and power production makeup water systems.

The main groundwater table beneath the coastal terrace north and south of the plant is controlled by sea level at the coastline and gradually rises beneath the hills southeast of the plant. Hence, this water table beneath the plant is about the elevation of Diablo Creek, sloping upward from sea level at the coast to 200 ft above the 500 kV switchyard.

Groundwater in the alluvium of Diablo Creek is documented from makeup water wells that were operated on the plant site during the current licensed period. Makeup water wells No. 1 and No. 2 with collar elevations at 232 ft above mean sea level (MSL) and 333.3 ft MSL, respectively, produced water from the alluvium in Diablo Creek and from fractured sandstone and dolomite of the Obispo Formation. The water table varies, depending on the month of the year, but is generally controlled by flows in the alluvium near elevation 200 ft MSL. Makeup water well No. 2 (Deep Well #2) is currently the only operable permitted freshwater well. Former makeup water well No. 1 is no longer active or serviceable.

Groundwater above the base of the thick terrace deposits is recorded in several places. On the terrace north of Diablo Creek, monitoring wells MW-1 through MW-4 (collar elevations range between 115 and 210 ft MSL) at the closed waste holding pond showed water levels in 1985 at elevations between 64 and 127.5 ft MSL. These monitoring wells were subsequently closed and filled in 2005, and therefore are no longer operable. In parking lot 7, south of DCPP, two piezometers in 1996 and 1997, recorded groundwater at a depth of 40 to 77 ft and recorded a perched water table near the top of the wave-cut bedrock platform. Groundwater seeps also issue from a perched water table on the marine terrace platform (about 30 ft MSL) in Patton Cove. Local perched water tables also occur within the Obispo Formation above the marine bedrock platforms. These perched water tables occur on impermeable strata, such as clay beds, within the Obispo Formation. An example is the small spring that issues from the hillslope above and east of Patton Cove at elevation about 600 ft MSL. A few areas of dense vegetation indicative of seeps also issue from bedrock along the lower canyon walls of Diablo Creek below the Raw Water Reservoir.

DCPP groundwater use is limited to the periodic draw of freshwater supply from an onsite deep well. The groundwater source is geologically isolated to the DCPP watershed, and is therefore not hydraulically connected to other area groundwater resources. The surface streambed of Diablo Creek is not used as a freshwater supply resource. Groundwater is used only as required to supplement supply of the Raw Water Storage Reservoirs which feed the emergency firewater, plant site domestic water, and power production makeup water systems. The primary source of freshwater for power plant operations is seawater reverse osmosis. Uses of groundwater will not change as a result of the proposed action.

2.3.1 Groundwater Monitoring

In 2006, the Nuclear Energy Institute (NEI) launched the Groundwater Protection Initiative (NEI 07-07) to provide an industry-wide approach to unexpected groundwater and soil releases at operating and decommissioned nuclear power plants. In support of this industry initiative, DCPP implemented the DCPP Radiological Environmental Monitoring Program (REMP). The REMP samples from several onsite observation wells as well as Deep Well #2 (see Figure 2.3-1) to monitor for tritium. Tritium groundwater monitoring is also discussed in Chapter 5.

2.4 CRITICAL AND IMPORTANT TERRESTRIAL HABITATS

DCPP is located in coastal San Luis Obispo County, California directly southeast of Montana de Oro State Park. The DCPP industrial site encompasses approximately 585 acres. The site contains the main generating facilities, office buildings, warehouses, parking lots, switchyard, Independent Spent Fuel Storage Installation (ISFSI), and the Old Steam Generator Storage Facility.

As discussed in Section 2.1, PG&E owns approximately 12,000 acres of land north and south of DCPP. These lands form a long relatively narrow strip comprised of gently sloping coastal marine terrace with steeply rising hills to the east. The PG&E-owned lands extend approximately 14 miles from near the community of Avila Beach, north to the southern boundary of Montano de Oro State Park. They vary from about 0.5 miles to 1.75 miles in width.

2.4.1 Land Use for Stock Animals and Grazing

High-Intensity Short-Duration (HISD) grazing, sometimes called holistic grazing (Reference 56), or high intensity – low frequency grazing (Reference 52) has been in use on PG&E lands north of DCPP since 1991. HISD grazing attempts to more closely mimic the grazing behavior exhibited by wild free ranging ungulate populations (e.g., bison, antelope, etc.). Wild herds tend to remain bunched for protection from predators, while continuously moving across seasonal ranges following traditional movement corridors. HISD grazing places an entire herd of livestock together in one relatively small paddock for a short period of time (typically a few days) before the herd is moved to the next paddock, allowing the first paddock to rest. Because of the high number of paddocks involved each receives significant rest between grazing episodes. This results in more uniform forage use while improving growth and reproduction of native perennial grass species.

Transitioning to HISD grazing required an investment in new infrastructure (fencing and water systems) that PG&E helped to facilitate. This was necessary because of the need to begin rotating livestock through a larger number of smaller paddocks to achieve more uniform forage use, and eliminate areas of over use.

Over the past 15 years, the property north of DCPP has been primarily a cow-calf operation. This means that a production herd is maintained on the property year-round, and the annual calf crop is sold after weaning. Quantitative assessments of grazing capacity have been conducted on these lands to guide management decisions and administrative policy (References 50 and 57).

Grazing is also practiced on lands located south of DCPP. A small cow-calf herd is maintained year-round on paddocks that occur on the coastal terrace. Larger numbers of stocker cattle are seasonally pastured on uplands to the east of the coastal terrace.

Since 1991, grazing has been monitored annually in three ways: (1) stock flow records kept by the rancher on the northern lands document numbers of animals and time spent in each paddock throughout the year, (2) photo monitoring from permanent stations established throughout the property is conducted twice annually (spring and fall), and (3) quantitative measurement of residual dry matter is performed annually in the fall, before the first soaking rains.

2.4.2 Federally Designated Critical Habitat Areas

Critical habitat is a term defined and used in the federal Endangered Species Act of 1973 (16 USC 1361 et seq), as amended (ESA). It is a specific geographic area(s) that contains features essential for the conservation of a threatened or endangered species and that may require special management and protection. Critical habitat may include an area that is not currently occupied by the species but that will be needed for its recovery. An area is designated as “critical habitat” after the U. S. Fish and Wildlife Service (FWS) publishes a proposed Federal regulation in the Federal Register and then receives and considers public comments on the proposal. The final boundaries of the critical habitat area are also published in the Federal Register. Section 7 of the ESA prohibits the destruction or adverse modification of designated critical habitat areas by actions with a Federal nexus (i.e., occurring on Federal land, authorized under a Federal permit or license, or receiving Federal funding).

Critical habitat areas near or associated directly with the DCPP lands were identified using a geographic information system, and were verified using on-line maps available from the USFWS (Reference 58), or the National Marine Fisheries Service (Reference 54) website.

Several miles north of DCPP in the vicinity of Morro Bay and estuary, critical habitat areas have been designated for the following federally listed species:

- Morro Bay shoulderband snail - endangered
- Morro Bay kangaroo rat - endangered

One critical habitat area occurs along the coast in the immediate vicinity of DCPP and the PG&E-owned lands north and south of the plant site:

- South-Central Coast Steelhead DPS - threatened

Following the listing of the south-central coast steelhead DPS as threatened in 1997, the National Marine Fisheries Service, Department of Commerce, established critical habitat for the species (Reference 55). DCPP lies within the southern most Hydrologic Unit (Estero Bay 3310) of this DPS. All of the PG&E-owned lands north and south of the plant site also lie within this critical habitat area. The Federal Register rule package identifies streams that provide habitat suitable for this species within each Hydrologic Unit. Within the vicinity of DCPP, only Coon Creek, located north on the boundary with Montana de Oro State Park, is described.

Beginning in 2002, PG&E partnered with the City of San Luis Obispo, the National Marine Fisheries Service, and the California Department of Fish and Game in a successful steelhead habitat restoration project on this stream (Reference 48).

Steelhead (*O.mykiss*) are migratory anadromous rainbow trout. They hatch in fresh water, descend to the ocean, and return to fresh water to spawn. Depending on the stream, steelhead can be either summer or winter migrators but regardless of migration period, spawning usually takes place from March to early May. Steelhead were once common to most streams in central California (Reference 53).

Steelhead constitute various races of ocean-going forms of rainbow trout that are native to Pacific coast streams from Alaska south to northwestern Mexico. Once hatched, juvenile steelhead may stay in freshwater for 1 or 2 years before migrating to the ocean. This outward migration primarily occurs during the winter and spring months when river flows are relatively high. Steelhead mature at ages two to four and migrate back upstream to natal spawning areas. The upstream migration generally occurs from January through March, but is dependent on the intensity of storms and subsequent outflow. After a female steelhead lays her eggs in a gravel nest, a male fertilizes the eggs. After fertilization, the nest is covered by a layer of gravel and the eggs incubate and hatch, repeating the cycle.

Section 3.1.7 describes the transmission lines that were built to connect DCPP to the transmission grid system (Figure 3.1-6). The three 500 kV lines each traverse approximately 80 miles of ecologically diverse landscape. The double-circuit 230 kV line traverses approximately 10 miles of landscape. Beginning just east of DCPP, these lines cross steep upland terrain with dense vegetative cover of chaparral, coastal scrub, and oak woodland. Further east, the landscape changes to rolling hills with grassland cover. Patches of brush and oak occur here as well as narrow bands of riparian vegetation located along stream courses. Considerable agricultural development is also prevalent including row crops, irrigated pasture and vineyards. Still further east, the landscape becomes increasingly arid, tree cover diminishes and is replaced by desert saltbush scrub and grass cover. This condition persists into the San Joaquin Valley where agricultural development is again possible due to the importation of water resources through the canals of California’s extensive Central Valley Water Project.

Designated watershed areas crossed by the transmission lines include: Carrizo Plain, Coast Range, Estero Bay, Estrella River, Upper Tulare, Lower Tulare, Salinas, Santa Maria, Sunflower Valley, and Temblor (Reference 47).

Within the vicinity of the project high-voltage transmission lines, critical habitat areas have been designated for the following federally listed species:

- Vernal pool fairy shrimp - threatened
- Vernal pool longhorn fairy shrimp - endangered
- California red-legged frog - endangered

- California tiger salamander – endangered
- California condor – endangered

Of those federally listed species above, the vernal pool fairy shrimp currently has critical habitat that is crossed by the Diablo-Gates 500 kV transmission line and associated towers and access roads.

The vernal pool fairy shrimp has a life span from December to early May (if water temperature stays below 75°F). Vernal pool fairy shrimp are filter and suspension feeders. Their diet mainly consists of unicellular algae, bacteria, and ciliates. They may also scrape algae, diatoms, and protists from the surface of rocks, sticks, and plant stems.

Shrimp eggs are laid by the adults each winter season. However, eggs may lie dormant in the soil for up to 10 years before hatching. Genetic diversity is important for the survival of any species. One pool's shrimp population may have genes another pool's population lacks. This diversity may mean that the first population survives a disease or other threat, which kills the population that does not have the needed gene. The genes of different shrimp populations can be mixed when eggs are moved from one pool to another via wind, water, or in the stomachs of migrating birds. Small, isolated populations of shrimp are more likely to become extinct because they lack the genetic diversity to withstand threats.

The vernal pool fairy shrimp is found scattered throughout the Central Valley from Shasta County to Tulare County, along the Coast Range from Solano County to San Luis Obispo and Santa Barbara Counties, and in southern California in Riverside and San Diego Counties.

A recently proposed expansion of critical habitat for the federally endangered California red-legged frog in San Luis Obispo County, if adopted, would involve another portion of the Diablo-Gates 500 kV transmission line located north of Highway 101 and east of Highway 41 (Reference 49).

2.4.3 Important State Natural Communities

Other important terrestrial habitats in the DCPP vicinity include community types considered unique or sensitive within California. These habitats include central maritime chaparral, coastal and valley freshwater marsh, coastal bluff scrub, valley saltbush scrub, valley sink scrub, vernal pool areas, serpentine chaparral and grasslands, and stream and river riparian habitats.

In the vicinity of DCPP, coastal maritime chaparral occurs on the higher ridges of the Irish Hills, north and south of the plant site where it has been reduced somewhat in area by transmission tower and access road development and maintenance. The central coast interior live oak riparian woodland associated with Diablo Creek, east of the 500 kV switch yard, and the central coast willow riparian community associated with Coon Creek north of the plant site, are managed using Best Management Practices developed by the Diablo Canyon Land Stewardship program and are treated as sensitive resource areas. North of the plant site, two sensitive community types, coastal bluff scrub and willow scrub riparian habitat support sensitive plant, animal, and fish populations. These communities were intensively studied from 2005 through 2006 in association with development of the Point Buchon Trail public access program that opened in 2008. PG&E monitors the effects of public access on sensitive species and communities, cultural resources, and sustainable agriculture annually and reports the results to the California Coastal Commission (References 44 and 27).

Most of the sensitive habitat types listed above can be found along the transmission line corridors. Map figures identifying these natural community types, wetland areas, and other land cover classifications associated with the project transmission corridors are presented in the Transmission Corridor Terrestrial Ecology Technical Report (Reference 51).

2.5 THREATENED OR ENDANGERED SPECIES

DCPP is located in San Luis Obispo County, as discussed in Section 2.1. Transmission lines from DCPP extend into Kern County, Fresno County, Kings County, and Monterey County.

A 2004 report written for the U.S Department of Energy, identified 85 threatened or endangered species that could be present in the vicinity of DCPP (Reference 62). The report also stated that as many as 36 of these species could be affected by operation and maintenance of the plant or transmission lines and associated rights-of-way. Many of these species (see Table 2.5-1), though present in California, have very limited geographical distributions that are further restricted by their dependence on certain special habitat elements. For this reason, many are not known to occur, nor are they likely to occur, within the vicinity of DCPP or its transmission lines.

2.5.1 PLANT SITE AND VICINITY

PG&E-owned lands in the vicinity of DCPP were inventoried for the presence of threatened and endangered species over the period of 1992 to 1997. This work was performed under the direction of the Diablo Canyon Land Stewardship Committee and the results were presented in two documents covering different parts of the total ownership (References 29 and 44). Additional studies were carried out in 1999 within and adjacent to Diablo Creek from near the outlet to the Pacific Ocean, to a point approximately one-half mile upstream from the 500 kV switch yard. These studies focused on the California red-legged frog (*Rana aurora draytonii*), which at that time had been recently listed by the U. S. Fish and Wildlife Service as threatened under the federal Endangered Species Act. No California red-legged frogs were found in the study area during this survey.

Further studies of threatened and endangered species were conducted over the period of 2005 to 2006 on lands north of the plant site (Reference 44).

The American peregrine falcon, California brown pelican, south-central coast steelhead trout DPS, and black abalone are species that are currently listed as threatened or endangered and have been identified as occurring within or near the plant site.

Among those marine mammals that frequent near-shore areas within the vicinity of the DCPP site, the southern sea otter is listed as threatened under the federal Endangered Species Act. One marine reptile, the green sea turtle, is known to occasionally frequent near-shore areas within the DCPP site vicinity. This species is listed as threatened under the federal Endangered Species Act.

American Peregrine Falcon - *Falco peregrinus anatum*

The peregrine falcon occupies breeding territories at select sites along the California coast north of Santa Barbara, in the Sierra Nevada Mountains, and in other mountains of northern California. In winter, this species is found throughout the Central Valley, and occasionally on the Channel Islands. Migrants occur along the coast and in the western Sierra Nevada in spring and fall. Breeding occurs mostly in woodland, forest, and coastal habitats. Riparian areas and coastal and inland wetlands are important habitats year-long. Suitable nesting habitat occurs in the form of isolated off-shore rocks and cliffs. Foraging habitat includes the air space above coastal terraces, coastal bluffs, and near-shore areas where prey (birds up to the size of ducks) are hunted on the wing.

Although the peregrine falcon habitat has not been mapped on the PG&E-owned lands, two active year-round peregrine falcon nesting territories are known to occur within the project vicinity. Both territories include nest sites located on off-shore rocks (References 44 and 61).

Once listed as endangered under the federal Endangered Species Act (ESA), the peregrine falcon has made a good recovery and the USFWS delisted the peregrine falcon from the federal endangered species list in 1999. As a condition of delisting, the USFWS has established a monitoring program to document breeding status of the falcon through 2015. The peregrine falcon is also designated by the USFWS as a "Bird of Conservation Concern" (BCC). Bird species with a BCC designation represent the USFWS's highest conservation priorities and draw attention to species in need of conservation action. In addition, the peregrine falcon continues to be protected under the federal Migratory Bird Treaty Act.

Although the peregrine falcon is currently listed as endangered under the California Endangered Species Act (CESA), the California Department of Fish and Game (CDF&G) has recommended delisting, and the Fish and Game Commission has voted to accept the petition to remove the peregrine falcon from the list of state endangered birds. Hearings on the proposed regulatory change will be held by the Fish and Game Commission during 2009. If delisted under CESA, the peregrine falcon will continue to be a "fully protected species" under Fish and Game Code Section 3511. Therefore, whether or not the species is listed pursuant to CESA, the legal prohibition on "take" of the species will remain in effect.

The peregrine falcon is also designated as "sensitive" by both the California Department of Forestry and Fire Protection (CDF) and the U.S. Department of Agriculture Forestry Service (USDA Forest Service). The CDF classifies sensitive species as those species that warrant special protection during timber operations. The USDA Forest Service defines sensitive species as those species for which population viability is a concern, as evidenced by downward trends in population numbers or density, or in habitat capability that would reduce a species' existing distribution.

Continuing exposure to toxic pesticides, primarily through migrant prey species, is the most important endangerment factor. Peregrine falcon populations have rebounded significantly since restrictions were placed on use of DDT in the United States.

California Brown Pelican - *Pelicanus occidentalis californicus*

The brown pelican is found in estuarine, marine subtidal, and marine pelagic waters along the entire California coastline. Brown pelicans breed on the Channel Islands (Anacapa, Santa Barbara, and Santa Cruz) from March to early August. In southern California, the brown pelican is common along the coast from June to October, especially within 20 miles of shore, but can be found as far as 100 miles out to sea. Off-shore rocks and coastal bluffs overlooking the water are used for roosting. No nesting by this species occurs along the Pecho Coast. Foraging is limited to off-shore open water areas.

Although, brown pelican habitat has not been mapped on the PG&E-owned lands, brown pelicans are frequently observed, outside the breeding season, along the Pecho Coast where they feed in open water areas off-shore and rest on off-shore rocks and along the outer edges of the coastal bluffs. When present in the vicinity, and accompanied by calm weather and ocean conditions, large numbers of brown pelicans can be observed resting on the intake cove breakwater structures during routine power plant operations.

The brown pelican was first declared endangered in 1970 under the Endangered Species Conservation Act (precursor to the ESA) due to sharp population declines and the threat of further declines from pesticide-contaminated food supplies. The brown pelican is still currently listed as endangered under the ESA, however in February 2008 the U.S. Fish and Wildlife Service published their proposed rule to remove the brown pelican from the Federal List of Endangered and Threatened Wildlife. Other federal laws such as the Migratory Bird Treaty Act and the Lacey Act will continue to protect the brown pelican, its nests, and its eggs should the rule be made final.

The brown pelican was officially removed from the California Endangered Species list in July 2009; however the brown pelican remains a fully protected species under Fish and Game Code Section 3511.

In spite of known threats (i.e., human disturbance, domoic acid poisoning, oil spills, starvation events, fish hook/line mortality), the breeding population of brown pelicans in California has increased substantially after the banning of DDT. In addition, the birds have returned to previously abandoned nesting sites in the Channel Islands. Many of the downlisting criteria for the brown pelican now meet or exceed the 5-year standard noted in the recovery plan.

No local endangerment factors associated with the plant site have been identified for this species.

Steelhead (south-central California coast DPS) – *Oncorhynchus mykiss irideus*

Steelhead trout belong to the family Salmonidae which includes all salmon, trout, and chars. Steelhead are the anadromous form of rainbow trout, native to western North

America and the Pacific Coast of Asia. The term anadromous refers to fish species born in fresh water that migrate to the ocean for an extended period of time before returning to fresh water to spawn. Steelhead may spend their first 1-3 years of life in fresh water. After spending between 1 to 4 growing seasons in the ocean, where most of their growth occurs, steelhead return to their native fresh water stream to spawn. Unlike Pacific salmon, steelhead do not necessarily die after spawning and may spawn more than once.

In California, most steelhead spawn from December through April in small streams and tributaries where cool, well oxygenated water is available year round. Following hatching, newly emerged fry move to shallow protected areas of the stream (usually in the stream margins). They establish feeding areas which they defend. Most juveniles can be found in riffles, although larger ones will move to pools or deep runs.

In California, steelhead were once abundant in coastal and Central Valley rivers and streams, however the statewide steelhead population has been in decline for more than 30 years. The major factor causing steelhead population decline is freshwater habitat loss and degradation. This has resulted from three main factors: inadequate stream flows, blocked access to historic spawning and rearing areas due to dams, and human activities that discharge sediment and debris into waterways.

Listed as a threatened species on August 18, 1997, threatened status was reaffirmed on January 5, 2006 (Federal Register, Vol. 17, No. 3). The south-central California coast DPS includes all naturally spawned *O. mykiss* (steelhead) populations below natural and manmade impassable barriers from the Pajaro River in Santa Cruz county south to but not including the Santa Maria River.

Critical habitat was designated in September 2005 and includes selected watersheds and coastal waters in San Luis Obispo County. Coon Creek, located north of DCPP, is identified as potential habitat within the Estero Bay Hydrologic Unit (3310) of this critical habitat designation.

Southern Sea Otter - *Enhydra lutris nereis*

The southern sea otter, which originally ranged from Baja California to at least Washington State and perhaps to south-central Alaska, was generally considered extinct by 1920 (Reference 60). Apparently, however, a group of 50 to 100 individuals survived off central California in the vicinity of Monterey. By 1970, the population had grown to include about 1,800 individuals. The southern sea otter now regularly occurs along about 300 km of the central California coast, and recently, individual sightings have been documented as far north as Fort Ross, California.

Although the sea otter is a marine mammal, it rarely ventures more than 1 km from shore. It forages in both rocky and soft-sediment communities, on or near the ocean floor. Off California, sea otters seldom enter waters of greater depth than 20 m. The sea otter is capable of spending its entire life at sea, but sometimes rests on rocks near the water. The diet consists mainly of slow-moving fish and marine invertebrates, such as sea urchins, crabs, abalones, and other mollusks.

Sea otter populations from Pt. Buchon to near Pt. San Luis (including the area adjacent to DCPP) have been monitored monthly since 1973. Average population size has varied over the years, but has seasonally ranged from less than 40 to over 100 individuals (Reference 59). In recent years, the study area population has remained relatively stable with an annual mean of approximately 70. Their distribution is known to change with local conditions and the population size appears to be largely influenced by the availability of food resources, suitable resting sites, pupping success, and movement of otters between adjacent coastal areas. Females and pups now dominate the study area, representing about 95 percent of the resident population. The females and pups form “rafts” where they float in small groups while resting and grooming.

A group of approximately 30 southern sea otters resides within the DCPP Intake Cove. These animals typically overnight within the cove and disperse to offshore foraging areas during the day. Preferred rafting locations in the immediate vicinity of the power plant include the protected areas of the intake cove, north Diablo Cove, and Lion Rock.

The southern sea otter is currently listed under the federal Endangered Species Act as threatened (listing date: January 14, 1977). Since receiving federal and state protection, the species has increased significantly in numbers throughout its current range. Local populations are affected to some extent by natural mortality factors such as predation and disease. Other factors affecting the abundance and availability of food resources also contribute to population fluctuations.

Green Sea Turtle - *Chelonia mydas*

On the Pacific coast, the green sea turtle was once common as far north as San Quintin Bay, Baja California, and occasionally reached bays along the coast of extreme southern California. It was formerly common in San Diego Bay. The green sea turtle inhabits lagoons and bays of the continental shores and oceanic islands, especially where there are sandy beaches. It is most often encountered in relatively shallow water where it feeds upon marine plants, but individuals are also occasionally seen considerable distances from shore. Beds of algae (seaweed) or eelgrass are likely places of occurrence. Rock cavities may be used as places of retreat. The Pecho Coast affords little in the way of nesting habitat for this species.

Green sea turtles have been recorded in the DCPP vicinity on multiple occasions, being observed both in the open ocean and in the power plant intake cove. On two occasions in 1977 (prior to reactor start-up and plant commercial operation), once in 1994, two occasions in 1997, two occasions in 1999, once in 2000, once in 2001, once in 2007, and once in 2009, green sea turtles were found in the forebay of the DCPP intake structure. The turtles were discovered on the ocean surface inside the concrete intake curtain wall in front of the debris exclusion bar racks. On each occasion, the turtles appeared unharmed, and swam freely once returned to the open ocean.

This species is listed as threatened under the federal Endangered Species Act (listing date: July 1978) due to declining populations and limited breeding areas. No local endangerment factors have been identified for this species.

Black Abalone - *Haliotis cracherodii*

The black abalone is one of seven species of abalone that occur in California, and is the only species that occurs primarily in the marine intertidal zone where it is found on the faces, overhangs, and cracks of rocks. This species of abalone has a geographic range from Mendocino County in northern California south to southern Baja California. Though less desirable from a fisheries perspective than other abalone types, commercial harvesting of black abalone occurred within the species' range peaking in 1973 at almost 2 million lbs, followed by declines leading to catches of less than 220,000 lbs by 1988.

Surveys of black abalone in the Channel Islands by the CDF&G in the mid-1970s were conducted prior to opening the area to commercial harvesting. Data from those surveys recorded densities of greater than 100 black abalone per m^2. Black abalone also occurred in high abundances in the areas around DCPP including Diablo Cove where the population was estimated at over 13,000 individuals in 1981.

In 1986 and 1987, black abalone with severely shrunken body masses were found in several of the Channel Islands off the coast of California (References 65 and 69). The afflicted animals were characterized by epipodial and mantle tissue that was discolored, flaccid, and atrophied. In severe cases abalone that were normally firmly attached to rocks by their foot muscle were hanging from the rocks barely attached. The condition was termed withering syndrome (WS) (Reference 65). In areas with WS, there were also large numbers of empty shells that appeared to be the result of recent deaths. Between 1986 and 1989 population declines in excess of 90 percent had occurred on the southernmost Channel Islands, while on the more northern island of San Miguel, declines were less severe (References 65 and 69).

In June 1988, black abalone with WS were found along the shoreline of north Diablo Cove. A black abalone population census in Diablo Cove was conducted as part of the Receiving Water Monitoring Program for DCPP from 1981 through 1998. Similar to the rapid population declines observed in the Channel Islands, results from this study showed that mean density of black abalone declined from approximately 0.9 per m^2 in 1988 to approximately 0.1 per m^2 in 1991. The black abalone with WS that were found in Diablo Cove and the surrounding areas had symptoms that were identical to those observed in the Channel Islands. Further evidence showed that WS is caused by a Rickettsiales-like prokaryotic pathogen that invades digestive epithelial cells and disrupts absorption of digested materials from the gut lumen into the tissues (Reference 64). The pathogen has been found in black abalone from throughout the state. The initial appearance on the mainland of WS with accompanying die-off at DCPP likely resulted from the absence of any other long-term monitoring program along the coastline, and the general low abundances of black abalone in the populated areas of southern California.

Continued monitoring of the condition at DCPP occurred following the initial WS-related die-off in 1988. Although populations increased during some years, WS contributed to an overall decline in Diablo Cove by 1998 from peak abundances in the early 1980s of greater than 95 percent. Monitoring at stations in areas outside of Diablo Cove showed similar levels of decline (Reference 67). As of January 2008, all known black abalone populations south of Monterey County, California, have experienced major losses, which have been largely attributed to WS (Reference 70). Available evidence indicates that mass mortalities associated with the disease continue to expand northward along the California coast especially during warm water El Niño periods (Reference 67). Similar widespread mass mortalities of black abalone over the past two decades have also been reported from Mexico verifying the widespread nature of WS (Reference 70).

The relationship between the rate of WS-related mortalities in black abalone and increased seawater temperature was established in experiments done at DCPP (Reference 68). Other experiments conducted in more detail using different test temperatures showed similar results and concluded that “elevated temperature was not a direct cause of WS, but accelerated the mortality of black abalone with WS” (Reference 63). In contrast to the WS-related mortalities associated with increased seawater temperatures, earlier laboratory temperature studies on black abalone at DCPP prior to plant operations showed high levels of temperature tolerance (Reference 66). Growth studies conducted over a 90 day period showed that optimal growth occurred at approximately 64ºF and that abalone held at approximately 75ºF over the same period showed no mortality. These results showed that healthy black abalone would be expected to survive the temperature regime in Diablo Cove during plant operation that began in 1985 and were consistent with the results from cove-wide census showing a healthy population of black abalone in Diablo Cove during the period of plant operation through 1988 when WS-related mortalities were first observed at the location. Thermal discharge from the operating power plant was therefore not a direct cause of black abalone WS later observed in the coastal vicinity.

As a result of the risk to the black abalone due to WS, the State of California suspended all forms of legal harvest of black abalone in 1993, and in 1997 placed all abalone harvests south of the Golden Gate under indefinite moratorium. On June 23, 1999 black abalone was added to the list of Candidate Species by the National Marine Fisheries Service (NMFS; Federal Register 64 33466), in the context of consideration for federal protected status pursuant to the Endangered Species Act of 1973 as amended. The black abalone was transferred to the NMFS List of Species of Concern on April 15, 2004 (Federal Register 69 19975). The NMFS initiated a formal status review in June 2007 as mandated by the ESA.

As a result of the status review, a proposal to list black abalone as endangered, a solicitation for public comment on the proposed rule, and solicitation for additional information regarding black abalone status and habitat needs, were published in the Federal Register on January 11, 2008 (Federal Register 73 1986). A final rule formally designating the black abalone as an endangered species was published on January 14, 2009 (Federal Register 74 1937).

2.5.2 TRANSMISSION LINE CORRIDORS

In 2008, a review was performed of known information regarding special-status plant and wildlife species and habitats within 1 mile of the DCPP transmission lines. Special-status species include (1) those listed or considered candidates for listing under the state and/or federal endangered species acts; (2) species designated "of concern" by the USFWS and/or California Department of Fish and Game (CDF&G), or (3) are listed as threatened or endangered (Lists 1 and 2) by the California Native Plant Society (CNPS). Sources used in identifying these species are included in the Transmission Corridor Terrestrial Ecology Technical Report (Reference 51).

Sensitive species and habitats known to occur or potentially occurring in the vicinity of the DCPP transmission line corridors are shown in Tables 2.5-2 and 2.5-3. Table 2.5-2 lists special-status plant species with potential to occur within the DCPP transmission line corridors, their status, habitat requirements, and project quads (see Figure 2.5-1) in which they occur. Thirty-nine special-status plant species were identified from background research. Of these, six plant species are federally- or California state-listed as rare, threatened, or endangered:

- San Luis Obispo fountain thistle (*Cirsium fontinale var. obispoense*)
  Federally and California state endangered, CNPS list 1B.2
- Pismo clarkia *(Clarkia speciosa ssp. immaculata)*
  Federally endangered, California state rare, CNPS list 1B.1
- Kern mallow (*Eremalche kernensis*)
  Federally endangered, no state status, CNPS list 1B.1
- Indian Knob mountainbalm (*Eriodictyon altissimum*)
  Federally- and California state endangered, CNPS list 1B.1
- San Joaquin woollythreads (*Monolopia congdonii*)
  Federally endangered, no state status, CNPS list 1B.2
- adobe sanicle (*Sanicula maritima*)
  No federal listing, California state rare, CNPS list 1B.1

All six species occur in close proximity to one or more of the DCPP transmission lines and suitable habitat may occur on private lands within the corridors.

Table 2.5-3 lists wildlife species with potential to occur along the lines, their status, habitat requirements, and project quads (see Figure 2.5-1) in which they occur. Twenty-three special-status wildlife species were identified from background research. Of these, the following 13 species are federally- or California State listed as threatened or endangered:

- Nelson's antelope squirrel (*Ammospermophilus nelsoni*)
  No federal status, California state threatened
- Longhorn fairy shrimp (*Branchinecta longiantenna*)
  Federally endangered, no state status
- Vernal pool fairy shrimp (*Branchinecta lynchi*)
  Federally threatened, no state status
- Morro Bay kangaroo rat (*Dipodomys heermanni morroensis*)
  Federally and California state endangered
- Giant kangaroo rat (*Dipodomys ingens*)
  Federally and California state endangered
- Tipton kangaroo rat (*Dipodomys nitratoides nitratoides*)
  Federally and California state endangered
- Tidewater goby (*Eucyclogobius newberryi*)
  Federally endangered, no state status
- Blunt-nosed leopard lizard (*Gambelia sila*)
  Federally and California state endangered
- Steelhead - south/central California coast DPS (*Oncorhynchus mykiss irideus*)
  Federally threatened, no state status
- California red-legged frog (*Rana aurora draytonii*)
  Federally threatened, California state species of concern
- Buena Vista Lake shrew (*Sorex ornatus relictus*)
  Federally threatened, no state status
- Giant garter snake (*Thamnophis gigas*)
  Federally and California state threatened
- San Joaquin kit fox (*Vulpes macrotis mutica*)
  Federally endangered and California state threatened

Of these listed species, blunt-nosed leopard lizard, Nelson's antelope squirrel, and San Joaquin kit fox are the most likely to occur within the corridors because of suitable habitat and known proximity to the transmission lines. In particular, the San Joaquin kit fox could potentially occur throughout much of the corridors; this species is known to occur in the San Joaquin Valley, California Valley, and in valleys just inland of the Coast Ranges in Santa Barbara, San Luis Obispo, and Monterey counties. California coastal steelhead and California red-legged frog have potential to occur in several coastal streams that are within the corridors. Approximately 2 miles of the Diablo-Midway #2 & #3 500 kV lines lie just outside (~ 260 ft, south) of federally designated Longhorn Fairy Shrimp critical habitat, located in the Carrizo Plain region of the project, and approximately nine-miles of the Diablo-Gates #1 500 kV line is located within federally designated Vernal Pool Fairy Shrimp critical habitat.

On September 16, 2008 the USFWS proposed a significant new expansion of critical habitat for the California red-legged frog (*Rana aurora draytonii*) (53492 Federal Register / Vol. 73, No. 180 / Tuesday, September 16, 2008 / Proposed Rules). If adopted as proposed the new critical habitat designation for this species in San Luis Obispo County would include approximately 12 miles of the Diablo-Gates # 1 500 kV transmission line.

Among the sensitive, non-listed species, American badger and burrowing owl could potentially occur in grassland and open oak woodland habitats. Silvery legless lizard could occur in chaparral and coastal scrub habitats. Refer to Table 2.5-3 for details of the listed and other sensitive wildlife species with potential to occur in the DCPP transmission line corridors.

Table 3 of the Transmission Corridor Terrestrial Ecology Technical Report summarizes habitats, wetlands, and special-status species referenced by tower span. For more on designated Critical Habitat Areas, refer to Section 2.4.

2.5.3 ESSENTIAL FISH HABITATS

In 1976, the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson Act) established a management system to more effectively utilize the marine fishery resources of the United States. It established eight Regional Fishery Management Councils (Councils), consisting of representatives with expertise in marine or anadromous fisheries from the constituent states. The Pacific Fishery Management Council (PFMC) is responsible for managing certain groundfish, coastal pelagic species, highly migratory species, and salmon from 3 to 200 miles off Washington, Oregon, and California. As amended in 1986, the Magnuson Act required Councils to evaluate the effects of habitat loss or degradation on their fishery stocks and take actions to mitigate such damage. In 1996, this responsibility was expanded to ensure additional habitat protection.

Essential fish habitat (EFH) is defined in the Magnuson-Stevens Fishery Conservation and Management Act as "…those waters and substrate necessary for spawning, breeding, feeding or growth to maturity". For the purpose of interpreting the definition of EFH, the term "waters" includes aquatic areas historically used by fish. Where appropriate this can include such environs as open waters, wetlands, estuarine, and riverine habitats. The term "substrate" includes sediment, hard bottom, structures underlying the waters, and the biological communities associated with the substrate. "Necessary" means the habitat is required to support a sustainable fishery and a healthy ecosystem; and "spawning, breeding, feeding or growth to maturity" covers a species' full life cycle.

In accordance with these definitions and descriptions, EFH would include a variety of elements found within, but not exclusive to, the coastal waters surrounding DCPP including the waters of Diablo Cove and the Intake Cove. The variety of substrates within these waters ranges from flat bottom areas covered with fine silt, sand, or shell fragments to high-relief areas comprised of large boulders and upthrust bedrock. Many areas are also covered with rocky cobble and gravel, and the varied substrates extend from the continuously submerged subtidal areas up through the intertidal shoreline. Manmade structures or components make up a portion of the substrate and include the intake and discharge structures, and the two large breakwaters that enclose the Intake Cove. Associated with the wide variety of substrates is an equally varied marine flora that grows upon it and constitutes part of the EFH. The subtidal and intertidal flora includes beds of giant kelp (*Macrocystis pyrifera*) and bull kelp (*Nereocystis luetkeana*), a wide variety of smaller, understory algal species, and surf grass beds. Different combinations of substrate and flora provide habitat for an equally varied collection of fish species. For example, several species of rockfishes (*Sebastes* spp.) can be found swimming in the midwater, beneath the kelp canopy, while gobies and sculpins utilize the rocky substrate below and shelter beneath smaller species of red and brown algae.

The marine environment in the vicinity of DCPP has been the object of intense environmental monitoring since the mid-1970s. These studies were initiated during the construction of DCPP and have continued, uninterrupted, through more than 20 years of plant operation. Various analysis reports have been consistent in their conclusions that biological effects of the discharge are mainly confined to Diablo Cove and diminished with both depth and distance from the point of discharge. A bibliography of various studies at DCPP that have addressed environmental impacts on EFH and other aspects of the marine environment in the vicinity of the plant are listed in the Essential Fish Habitat Technical Data Report (Reference 71).

EFH guidelines identify habitat areas of particular concern (HAPC) as types or areas of habitat that are identified based on one or more of the following considerations:

- The importance of the ecological function provided by the habitat.
- The extent to which the habitat is sensitive to human-induced environmental degradation.
- Whether, and to what extent, development activities are or will be stressing the habitat type.
- The rarity of the habitat type.

Three of the HAPC identified in the federal regulations are directly influenced by DCPP. They include rocky reefs, canopy kelp, and seagrass. The following descriptions include an overview of these habitat types and how they have been affected by power plant operation.

Rocky Reefs

Rocky habitats are generally categorized as either nearshore or offshore in reference to the proximity of the habitat to the coastline. Rocky habitat may be composed of bedrock, boulders, or smaller rocks, such as cobble and gravel. Hard substrates are one of the least abundant benthic habitats, yet they are among the most important habitats for groundfish. The rocky reefs HAPC includes those waters, substrates and other biogenic features associated with hard substrate (bedrock, boulders, cobble, gravel, etc.) to mean higher high water.

As mentioned earlier, construction of the breakwaters, intake, and discharge structures at DCPP affected the quantity and quality of rocky reef substrates in the Intake Cove and Diablo (Discharge) Cove. The net result, however, was that despite early disruption of habitat during the construction phase, subsequent re-colonization by native marine species of kelp, other algae, and invertebrates provided stable rock habitat that has supported indigenous nearshore fish assemblages. The habitat supported sport and commercial nearshore fisheries until it was protected from fishing by a security exclusion zone around DCPP in 2001.

Canopy Kelps

Of the habitats associated with the rocky substrate on the continental shelf, kelp forests are of primary importance to the ecosystem and serve as important groundfish habitat. Kelp forest communities are found relatively close to shore along the open coast. These subtidal communities provide vertically-structured habitat throughout the water column: a canopy of tangled blades from the surface to a depth of ten feet, a midwater, stipe region, and the holdfast region at the seafloor. Kelp stands provide nurseries, feeding grounds, and shelter to a variety of fish species and their prey. Giant kelp communities are highly productive relative to other habitats, including wetlands, shallow and deep sand bottoms, and rock-bottom artificial reefs. The net primary production of seaweeds in a kelp forest is available to consumers as living tissue on attached plants, as drift in the form of whole plants or detached pieces, and as dissolved organic matter exuded by attached and drifting plants.

Kelp canopies are widespread along the 11 mile coastline in the vicinity of DCPP, reaching maximum extent in fall months and occupying most rock reefs shallower than approximately 33 ft. Coastal aerial photographs spanning a 30-year period (1969–1998) were analyzed to determine potential effects of the DCPP discharge on kelp surface canopies in Diablo Cove and adjoining nearshore areas north of Diablo Cove. This study area represented a segment of about 1.2 mi of the greater DCPP coastline. Both bull kelp (*Nereocystis luetkeana*) and giant kelp (*Macrocystis pyrifera*) occurred in the study area. Areas contacted by the discharge were tested for long-term changes relative to controls using a before-after-control-impact statistical model.

Bull kelp declined significantly in Diablo Cove after power plant start-up due to its inability to grow and reproduce in the warm water. It remained, however, at low levels of abundance in some of the marginal areas of the cove where cooler offshore water was entrained by the discharge circulation. Test results were inconclusive for bull kelp declines outside of Diablo Cove, possibly due to the mixed canopy composed of bull kelp and giant kelp.

Giant kelp was more tolerant of the warmer conditions, and the combined coverage of bull kelp and giant kelp (total kelp cover) for the study area increased from about 7.5 acres to about 49.9 acres between the pre-operation and operation study periods. However, this absolute increase actually represented a statistically significant decline relative to control areas where total kelp cover increased by larger amounts over time. The differing rates of increase could have been related to natural variation associated with the mixed canopies, substrate availability, competition, and power plant effects.

The estimate of the annual average amount of bull kelp canopy lost in Diablo Cove during plant operation was 0.4 acres. A replacement canopy of giant kelp increased in Diablo Cove starting in the early 1990s from near-zero abundance to an annual average of about 1.3 acres. Giant kelp was greatest in abundance in 1998 (13.2 acres). The shift confirmed earlier predictions that bull kelp would decline near the discharge while giant kelp would increase.

The increased abundance of giant kelp habitat in Diablo Cove after plant start-up coincided with increased abundances of some kelp-associated fish species, such as kelp bass, and provided shelter for some juvenile rockfish species (e.g., kelp, gopher, black-and-yellow) that use kelp habitat for successful settlement in the nearshore zone. The increased diversity and numbers of midwater fishes during operation, and the continued increases of benthic fishes in north Diablo Cove may also have been related to the added structural complexity provided by giant kelp.

Seagrasses

Two important seagrass species found on the West Coast of the U.S. are eelgrass (*Zostera* spp.) and surfgrass (*Phyllospadix* spp.). These grasses are vascular plants, not seaweeds, forming dense beds of leafy shoots year-round in the lower intertidal and subtidal areas. Eelgrass is found on soft-bottom substrates in intertidal and shallow subtidal areas of estuaries and occasionally in other nearshore areas, such as the Channel Islands. Surfgrass occurs on hard-bottom substrates along higher energy coastlines. Studies have shown seagrass beds to be among the areas of highest primary productivity in the world.

Analysis of long-term monitoring data showed that the DCPP thermal discharge caused surfgrass to become less abundant in Diablo Cove after plant start-up. Based on earlier observations, prior to power plant start-up, surfgrass once formed a nearly continuous band around the shoreline of Diablo Cove, covering an estimated area of about 5 acres. Severe storm waves in winter 1982/83, before power plant start up, subsequently reduced surfgrass cover in Diablo Cove to about 1 acre. Surveys in summer/fall 1997 showed that surfgrass cover in Diablo Cove was about 0.25 acres. Based on these qualitative estimates, the operation of the DCPP discharge reduced the cover of surfgrass in Diablo Cove by about 0.75 acres. Lack of recovery to pre-storm abundances represented a potential loss of approximately 4.75 acres of surfgrass in Diablo Cove. Areas in Diablo Cove that lacked surfgrass were generally suitable for its establishment in terms of substratum composition and depth, but the areas were covered with algae instead. The specific causes for the declines and the lack of recovery are unexplained. Healthy patches of surfgrass remained in certain portions of north and south Diablo Cove long after plant start-up despite chronic exposure to warmer water temperature regimes.

2.6 DEMOGRAPHY

2.6.1 REGIONAL DEMOGRAPHY

The Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) presents a population characterization method that is based on two factors: "sparseness" and "proximity" (Reference 77). "Sparseness" measures population density and city size within 20 miles of a site and categorizes the demographic information as follows:

Demographic Categories Based on Sparseness

		Category
Most sparse	1.	Less than 40 persons per square mile and no community with 25,000 more persons within 20 miles
	2.	40 to 60 persons per square mile and no community with 25,000 or more persons within 20 miles
	3.	60 to 120 persons per square mile or less than 60 persons per square mile with at least one community with 25,000 or more persons within 20 miles
Least sparse	4.	Greater than or equal to 120 persons per square mile within 20 miles
Source: Reference 77		

"Proximity" measures population density and city size within 50 miles and categorizes the demographic information as follows:

Demographic Categories Based on Proximity

		Category
Not in close proximity	1.	No city with 100,000 or more persons and less than 50 persons per square mile within 50 miles
	2.	No city with 100,000 or more persons and between 50 and 190 persons per square mile within 50 miles
	3.	One or more cities with 100,000 or more persons and less than 190 persons per square mile within 50 miles
In close proximity	4.	Greater than or equal to 190 persons per square mile within 50 miles
Source: Reference 77		

The GEIS then uses the following matrix to rank the population category as low, medium, or high.

GEIS Sparseness and Proximity Matrix

		Proximity			
Sparseness		1	2	3	4
	1	1.1	1.2	1.3	1.4
	2	2.1	2.2	2.3	2.4
	3	3.1	3.2	3.3	3.4
	4	4.1	4.2	4.3	4.4

Source: Reference 77

Low Population Area | Medium Population Area | High Population Area

PG&E used 2000 census data from the U.S. Census Bureau (Reference 74) and the estimates prepared by California Department of Finance to determine most demographic characteristics in the DCPP vicinity. The calculations determined that 119,840 people live within 20 miles of DCPP, producing a population density of 153 persons per square mile. Applying the GEIS sparseness measures identifies DCPP as falling into sparse Category 4 (greater than or equal to 120 persons per square mile within 20 miles).

To calculate the proximity measure, PG&E determined that 424,013 people live within 50 miles of DCPP, which equates to a population density of 82 persons per square mile. Applying the GEIS proximity measures, DCPP is classified as Category 2 (No city with 100,000 or more persons and between 50 and 190 persons per square mile within 50 miles). Therefore, according to the GEIS sparseness and proximity matrix, DCPP ranks of sparseness, Category 3, and proximity, Category 2, result in the conclusion that DCPP is located in a medium population area.

The nearest major metropolitan area is Santa Barbara (approximately 85 miles southeast), with a 2000 population of 92,325 (Reference 74). The population distribution within a 50-mile radius of DCPP is generally considered rural. Minor exceptions to this are Atascadero (20 miles northeast), San Luis Obispo (12 miles northeast), Five Cities encompassing Arroyo Grande, Grover Beach, Pismo Beach, Oceano, and Shell Beach (15 miles southeast) and Santa Maria (30 miles southeast) where the 2000 populations were 31,256, 40,541, 46,129, and 51,228, respectively (Figure 2.1-1). The municipality nearest the DCPP is the City of San Luis Obispo (12 miles northeast) with a 2000 population of 40,541 (Reference 74).

San Luis Obispo County and parts of Santa Barbara County are located within 50 miles of DCPP. The Metropolitan Statistical Areas (MSA) are San Luis Obispo, Atascadero, and Paso Robles of San Luis Obispo County and Santa Maria and Lompoc of Santa Barbara County (Reference 74).

From 1990 to 2000, the population of the San Luis Obispo-Paso Robles MSA decreased from 246,681 to 217,162, a decrease of 11.96 percent (Reference 74). The population of Santa Maria increased from 61,284 to 77,423, an increase of 26.33 percent. The population of Lompoc increased from 37,649 to 41,103, an increase of 9.17 percent.

Because more than 86 percent of employees at DCPP reside in San Luis Obispo County and Santa Maria of Santa Barbara County, they are the counties with the greatest potential to be socioeconomically affected by license renewal at DCPP. Table 2.6-1 shows population estimates and decennial growth rates for these two counties. Values for the State of California are provided for comparison.

Over the last several decades, San Luis Obispo and Santa Barbara Counties have shown fluctuating positive growth rates. From both 1970 to 1980 and from 1980 to 1990, San Luis Obispo and Santa Barbara Counties' growth rates were all relatively large. From 1990 to 2000, the San Luis Obispo County population growth rate was 13.59 percent, while Santa Barbara County population increased by 8.08 percent.

2.6.2 MINORITY AND LOW-INCOME POPULATIONS

NRC's Policy Statement on the Treatment of Environmental Justice Matters in NRC Regulatory and Licensing Actions (Reference 76) and Nuclear Reactor Regulation's (NRR) Office Instruction LIC-203 (Reference 72) conclude that a 50-mile radius could reasonably be expected to contain potential environmental impact sites and that the state was the appropriate geographic area for comparative analysis. PG&E has adopted this approach for identifying the DCPP minority and low-income populations that could be affected by DCPP operations.

ArcView® geographic information system software was used to determine the minority characteristics by block group. PG&E included all block groups if any part of their area lay within 50 miles of DCPP[1]. The 50-mile radius includes 294 block groups (Table 2.6-2).

2.6.2.1 Minority Populations

The NRC Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues defines a "minority" population as: American Indian or Alaskan Native; Asian; Native Hawaiian or other Pacific Islander; Black Races, and Hispanic Ethnicity (Reference 75). Additionally, NRC's guidance requires that (1) all other single minorities are to be treated as one population and analyzed, and (2) the

[1] ArcView uses data from the U.S.Census Bureau. This data contains all correctional institutions, including prisons, jails, detention centers, or halfway houses (counted at the institution). The California Men's Colony, located north of San Luis Obispo, is included in the Aggregate Minority block group and is shown in Figure 2.6-1.

aggregate of all minority populations are to be treated as one population and analyzed. The guidance indicates that a minority population exists if either of the following two conditions exists:

- The minority population in the census block group or environmental impact site exceeds 50 percent.

- The minority population percentage of the environmental impact area is significantly greater (typically at least 20 percentage points) than the minority population percentage in the geographic area chosen for comparative analysis.

For each of the 294 block groups within the 50-mile radius, PG&E calculated the percent of the block group's population represented by each minority. If any block group minority percentage exceeded 50 percent, then the block group was identified as containing a minority population. DCPP selected the entire State of California as the geographic area for comparative analysis, and calculated the percentages of each minority category in the State. If any block group percentage exceeded the corresponding State percentage by more than 20 percent, then a minority population was determined to exist.

Census 2000 data for California characterizes 46.7 percent of the population White, 6.4 percent Black, 10.8 percent Asian, 0.3 percent Native Hawaiian/Pacific Islander, 0.5 percent American Indian/Alaskan Native, 32.4 percent Hispanic, 0.2 percent Other, 2.7 percent multi-racial, and 53 percent aggregate of minority races.

Table 2.6-2 presents the numbers of block groups in each county in the 50-mile radius that exceed the threshold for minority populations. Figures 2.6-1 and 2.6-2 locate the minority block groups within the 50-mile radius.

Based on the "more than 20 percent" or the "exceeds 50 percent" criteria, 2 of the following minority populations exist in the geographic area:

- American Indian or Alaskan Native;
- Asian;
- Native Hawaiian or Pacific Islander;
- Black;
- All Other Single Minorities;
- Multi-Racial Minorities; or
- Aggregate of Minorities.

Based on the "more than 20 percent" criterion:

- The Aggregate of Minority Races populations exist in 65 block groups (Table 2.6-2). Figure 2.6-1 displays the locations of these block groups.

- The Hispanic Ethnicity populations exist in 52 block groups (Table 2.6-2). Figure 2.6-2 displays the locations of these block groups.

2.6.2.2 Low-Income Populations

NRC guidance defines low-income population based on statistical poverty thresholds (Reference 5) if either of the following two conditions is met:

- The low-income population in the census block group or the environmental impact site exceeds 50 percent.

- The percentage of households below the poverty level in an environmental impact area is significantly greater (typically that least 20 percentage points) than the low-income population percentage in the geographic area chosen for comparative analysis.

Based on the “more than 20 percent” criterion, 12 block groups contain a low-income population (Reference 74). All block groups are in Santa Barbara County. Table 2.6-2 identifies the low-income block groups in the region of interest. Figure 2.6-3 locates the low-income block groups.

The San Luis Obispo County labor market shows an average family income for 2000 at $43,149. For 2001, the county unemployment rate was at 3.0 percent. The 2000 US Census Data reports the median household income in 2000 at $41,349, which is below the 2000 California median household income of $46,499. For 2006-2008, the US Census Bureau reports the San Luis Obispo County median household income at $57,722, which is below the California median household income of $61,154 (Reference 131).

2.6.3 TRANSIENT POPULATION

In addition to the resident population presented in the tables and population distribution charts, there is a seasonal influx of vacation and weekend visitors within a 50-mile radius, especially during the summer months. The influx is heaviest to the south along the coast from Avila Beach to south of Oceano.

During August, the month of heaviest influx, the maximum overnight transient population in motels and state parks in this area is approximately 100,000 persons. However, there are no significant seasonal or diurnal shifts in population or population distribution within the low population zone (LPZ).

Table 2.6-3 lists transient population for recreation areas within 50 miles of the site for the periods of record listed. Within the LPZ, the maximum-recorded number of persons at any single time is estimated to be 5,000. This figure is provided by the State Department of Parks and Recreation and corresponds to the maximum daytime use of Montana de Oro State Park. Overnight use is considerably less, with an estimated maximum of 400. Evacuation of these numbers of persons from the park in the event of a release of radioactive material could be accomplished as noted in Chapter 15 of the DCPP FSAR (Reference 2).

In addition to the seasonal influx of vacation and weekend visitors, the San Luis Obispo and Santa Barbara County transient populations also includes migrant farm workers. Migrant farm labor was reviewed using the U.S. Department of Agriculture's National Agricultural Statistics Service (NASS) data for 2007. Actual migrant worker numbers are not directly reported; however, county level data on hired farm labor are available. NASS reported 166 of 905 farms hired migrant labor in San Luis Obispo County, and 81 farms, hiring only contract labor, hired migrants. NASS reported 148 of 776 farms hired migrant labor in Santa Barbara County, and 35 farms, hiring only contract labor, hired migrants. (Reference 132)

A total of 9,175 hired workers were reported in San Luis Obispo County, of which 4,805 were reported to work less than 150 days per year. In Santa Barbara County, a total of 21,768 hired workers were reported, of which 10,490 were reported to work less than 150 days per year. (Reference 132)

2.7 TAXES

PG&E pays annual property taxes to San Luis Obispo County based on the value of DCPP. The current tax revenues represent a substantial contribution to the local economy and are expected to continue to benefit the local population by helping to fund the local government and support necessary improvements to infrastructure.

For fiscal year 2008-09, the DCPP property tax payment to San Luis Obispo County was approximately $22.3 million (Reference 83). San Luis Obispo County is expected to generate $425 million for fiscal year 2008-09 based on the current taxable value (Reference 82). Between 48.4 and 48.9 percent of the 2007-08 and 2008-09 DCPP property tax payment has been received by the Unified School Districts (References 81 and 82).

For fiscal years 2004-05 through 2008-09, DCPP's property taxes represented 5.6 to 6.6 percent of San Luis Obispo County's total property tax revenues (Table 2.7-1).

The annual property taxes on DCPP are expected to remain relatively constant through the license renewal period. The State of California initiated deregulation of utilities in 1995. However, due to fluctuations in wholesales prices and numerous other issues, the California Public Utilities Commission suspended the deregulation effort in 2001. Should deregulation ever be reenacted in California, this could affect utilities' tax payments to counties. However, any changes to DCPP property tax rates due to deregulation would be independent of license renewal.

2.8 LAND USE PLANNING

This section focuses on San Luis Obispo County and Santa Barbara County because the majority of the permanent DCPP workforce lives in these two counties (see Section 3.4) and because DCPP pays property taxes in San Luis Obispo County.

As described in Section 2.6, over the last several decades, San Luis Obispo and Santa Barbara Counties have experienced fluctuating positive growth rates. From both 1970 to 1980 and from 1980 to 1990, San Luis Obispo and Santa Barbara Counties' growth rates were relatively large. From 1990 to 2000, the San Luis Obispo County population growth rate was 13.59 percent, while Santa Barbara County population increased by 8.08 percent (References 87 and 88).

As shown in Table 2.8-1, over the same period, 1990 to 2000, the number of housing units in San Luis Obispo County increased by 11.8 percent, and the number of housing units in Santa Barbara County increased by 3.3 percent, while the total number of units in the state increased by 10.8 percent. Median home values increased 7.3 percent in San Luis Obispo County, while values increased 14.9 percent in Santa Barbara County. The vacancy in San Luis Obispo and Santa Barbara Counties fell from 1990 to 2000. Santa Barbara County had the highest change in vacancy of approximately 24.8 percent in 2000 (References 89 and 90)

For 2000 to 2050, the California Department of Finance projects the population of San Luis Obispo County to increase by 32.4 percent, while the Santa Barbara County population to increase by 25.3 percent (Reference 73).

Both San Luis Obispo County and Santa Barbara County use comprehensive land use plans and zoning and subdivision regulations to guide development.

2.8.1 EXISTING LAND USE TRENDS

San Luis Obispo County covers 3,616 square miles of total area; 3,304 square miles is land and 311 square miles is water. Farming is a significant land use in the county (Figure 2.8-1). Land in the DCPP immediate vicinity is used for agriculture & livestock grazing (Reference 86).

Land use planning in San Luis Obispo County is guided by the Department of Planning and Building. The Agency has developed a land use plan, the Comprehensive Plan for San Luis Obispo County, to assess current land use trends and guide future land use decision-making. As shown in Table 2.8-1, there are approximately 102,275 homes sites within San Luis Obispo County (Reference 88).

Santa Barbara County covers 3,789 square miles of total area; 2,737 square miles is land and 1,052 square miles is water. Land use planning in Santa Barbara County is guided by the Department of Planning and Development. The Agency has developed a land use plan, the Comprehensive Plan for Santa Barbara County, to assess current land use trends and guide future land use decision-making. As shown in Table 2.8-1, there are approximately 142,901 homes sites within Santa Barbara County (Reference 88).

2.8.2 FUTURE LAND USE TRENDS

The San Luis Obispo County planning goals (Reference 84) are as follows:

- To maintain a high quality of life, sustain natural resources, and protect agricultural lands and rural character.
- To provide livable communities through plans that are responsive to local needs and vision.
- To encourage excellence in building design, cohesive and pedestrian oriented layouts, and streetscape improvements that help stimulate economic vitality and enhance downtown charm.

The Santa Barbara County planning goals (Reference 85) are as follows:

- To develop, promote and implement plans, policies and public improvements which enhance the quality of life for Santa Barbara County residents.
- To protect natural resources and promote sound long term economic development, while recognizing the differing needs and values of each of the County's unique communities and diverse rural areas.

2.9 SOCIAL SERVICES AND PUBLIC FACILITIES

2.9.1 PUBLIC WATER SUPPLY

DCPP is located in San Luis Obispo County, and the majority of site employees also reside within the County. Therefore, the discussion of public water supply systems will be limited to San Luis Obispo County.

Potable water for the city of San Luis Obispo is obtained principally from Salinas Reservoir, approximately 23 miles east-northeast of the DCPP site. Whale Rock Reservoir on Old Creek, 17 miles north of the site, and Chorro Reservoir, approximately 13 miles northeast of the site, are also used. A few small reservoirs are used in connection with the San Luis Obispo water system and are located approximately 18 miles northeast of the site. A reservoir in Lopez Canyon is 20 miles east of the site. Water is also imported into San Luis Obispo County from the California Water Project (Table 2.9-1). Smaller towns in the region of San Luis Obispo depend on wells for domestic water.

There are two public water supply groundwater basins within 10 miles of the DCPP site. Avila Beach County Water and Sewer District and the San Miguelito Mutual Water and Sewer Company provide water to the Avila Beach and Avila Valley area.

The licensees to the north and south of the DCPP site capture surface water from small intermittent streams and springs for minimal domestic use. Specifically, one resident approximately 1.5 miles north of the plant site maintains an artisan spring that supplies domestic water to the residence. PG&E and its grazing licensee north of the DCPP site capture water from springs in Crowbar Canyon, 1 mile north of the DCPP site, and from Diablo Creek. PG&E's grazing licensee south of the DCPP captures water from streams and springs between Pecho Canyon and Rattlesnake Canyon for livestock and low volume drip irrigation.

A seawater reverse osmosis desalinization facility was installed at the DCPP industrial site in 1985, and has been in continuous operation since then. As discussed in Section 3.1.2, it provides the majority of freshwater for plant primary and secondary systems makeup, fire protection system source water, and plant domestic water (including potable water) supply.

2.9.2 TRANSPORTATION

The existing roadway system within the DCPP property consists of a single private two-lane paved roadway (Diablo Canyon Road) that begins at Avila Beach Drive (approximately 6.75 miles from the plant). This roadway’s secured entry prevents public traffic from entering the site and using the road. This primary access road accommodates the current DCPP employee population during routine vehicle commute into and out of the industrial plant site. Immediately after leaving the access point, the primary roadway crosses east of San Luis Hill before continuing along a route parallel to the coastline near the base of the Irish Hills (References 86 and 91).

The primary road remains paved north of the power plant for a short distance and then connects with an unpaved road, which continues to the northerly PG&E boundary into Montana De Oro State Park. There is a secured gate across the road at this boundary. There are several other unpaved roads on the property. These unpaved roads, however, do not provide primary access for the majority of DCPP employees, and are used mainly by grazing licensees.

DCPP is accessed via the Avila Beach area. Only two routes connect to Highway 101 interchanges: Avila Beach Drive and San Luis Bay Drive. These two routes, west of the freeway, join into a single roadway leading to Avila Beach and the Harford Pier. Other roadways in the study area are generally classified as collectors or minor roadways. Employees traveling from either south or north will mostly use Highway 101 to reach either Avila Beach Drive or San Luis Bay Drive to access DCPP.

These routes are shown in Figure 2.9-1.

- **Avila Beach Drive.** Avila Beach Drive is a winding 4-1/2 mile long two-lane roadway from U.S. Highway 101 to its terminus at Port San Luis. East of Cave Landing Road, Avila Beach Drive maintains minimal shoulders as the roadway width is constrained on the south by steep rocky slopes and on the north by the parallel San Luis Obispo Creek. A short section of Avila Beach Drive was widened to install a left turn bay for eastbound vehicles turning north on San Luis Bay Drive. Additional left turn bays exist on the segment of Avila Beach Drive at Cave Landing Road and Ontario Road. West of Cave Landing Road, Avila Beach Drive maintains left-turn pockets at all intersecting collector roadways and generally accommodates summer peak parking demands along both shoulders.

- **San Luis Bay Drive.** San Luis Bay Drive begins just east of U.S. Highway 101 and terminates with an active traffic-light controlled intersection at Avila Beach Drive. The arterial roadway is generally used by trips originating or terminating north of Avila Beach, primarily in San Luis Obispo. Shoulders are provided along San Luis Bay Drive that are not wide enough to allow for parking.

- **Other Collector Roadways.** Collector roadways in the study area include Front Street, San Luis Street, San Miguel Street, Palisades Road, Cave Landing Road, See Canyon Road, and Monte Road. Front, San Luis, and San Miguel Streets are located in central Avila Beach. Front Street is located between the beach on the south and commercial shops to the north, beginning at Avila Beach Drive and terminating at the Unocal Pump Station entrance. San Luis Street and San Miguel Street provide access from Avila Beach Drive to the commercial and parking facilities at Avila Beach.

In determining the significance levels of transportation impacts for license renewal, the NRC uses the Transportation Research Board's Level of Service (LOS) definitions (Reference 77). LOS is a quantitative measure describing operational conditions within a traffic stream and their perception by motorists. Table 2.9-2 lists the current and future traffic conditions and LOS for the vicinity of DCPP.

2.9.3 EDUCATION

The state of California is divided into numerous school districts. San Luis Obispo County, where DCPP is located, has 13 school districts and 83 public schools. Santa Barbara County has 25 school districts and 125 public schools. Table 2.9-3 displays current San Luis Obispo County school district statistics, including the number of schools, number of students, and the student-to-teacher ratio.

2.10 METEOROLOGY AND AIR QUALITY

The DCPP site is adjacent to the Pacific Ocean in San Luis Obispo County, California, which is part of the South Central Coast Intrastate Air Quality Control Region (40 CFR 81.166).

The climate of the area is typical of the central California coastal region and is characterized by small diurnal and seasonal temperature variations and minimal summer precipitation. The prevailing wind direction is from the northwest, and the annual average wind speed is about 10 mph. In the dry season, which extends from May through September, the Pacific high-pressure area is located off the California coast, and the Pacific storm track is located far to the north. Moderate to strong sea breezes are common during the afternoon hours of this season while at night, weak offshore drainage winds (land breezes) are prevalent. There is a high frequency of fog and low stratus clouds during the dry season, associated with a strong low-level temperature inversion (Reference 2).

The mean height of the inversion base is approximately 1,100 ft. During the wet season, extending from November through March, the Pacific high-pressure area moves southward and weakens in intensity, allowing storms to move into and across the state. More than 80 percent of the annual rainfall occurs during this 5-month period. Middle and high clouds occur mainly with winter storm activity, and strong winds may be associated with the arrival and passage of storm systems. April and October are considered transitional months separating the two seasons (Reference 2).

The coastal mountains that extend in a general northwest-to-southeast direction along the coastline affect the general circulation patterns. The wind direction in many areas is more likely a result of the local terrain than it is of the prevailing circulation. This range of mountains is indented by numerous canyons and valleys, each of which has its own land-sea breeze regime. As the air flows along this barrier, it is dispersed inland by the valleys and canyons that indent the coastal range. Once the air enters these valleys and canyons, it is controlled by the local terrain features.

In areas where there are no breaks in the coastal range, the magnitude of the wind speed is increased and the variation in the wind direction decreases as the air is forced along the barrier. However, because of the irregular terrain profile and increased mechanical turbulence due to the rough terrain, vertical mixing and lateral meandering under the inversion are enhanced. Therefore, emissions injected into the coastal regime are transported and dispersed by a complex array of land-sea breeze regimes that lead to rapid dispersion in both the vertical and horizontal planes.

The annual mean number of days with severe weather conditions, such as tornadoes and ice storms at west coast sites, is zero. Thunderstorms and hail are also rare phenomena, the average occurrence being less than 3 days per year. The maximum recorded precipitation in the San Luis Obispo region is 3.28 inches in 1 hour at the

DCPP site, and 5.98 inches in 24 hours at San Luis Obispo. The 24-hour maximum and the 1-hour maximum occurred on March 4, 1978 (Reference 2).

The maximum recorded annual precipitation at San Luis Obispo was 54.53 inches during 1969. The average annual precipitation at San Luis Obispo is 21.53 inches. Rainfall recorded at the DCPP facility for the 10-year period July 1, 1997 through June, 30, 2007 averaged 21.46 inches. There are no fastest mile wind speed records in the general area of DCPP; surface peak gusts at 46 mph have been reported at Santa Maria, California, and peak gusts of 56 mph have been recorded at the 250-ft level at the DCPP site.

The current onsite meteorological monitoring system supporting DCPP operations will serve as the onsite meteorological measurement program for the period of extended operation. The system consists of two independent subsystems that measure meteorological conditions and process the information into useable data. The measurement subsystems consist of a primary meteorological tower and a backup meteorological tower. The program has been designed and continually updated to conform with Regulatory Guide 1.23, Revision 0 (Reference 97).

A supplemental meteorological measurement system is also located in the vicinity of DCPP. The supplemental system consists of two Doppler acoustic sounders and six tower sites. Data from the supplemental system are used for emergency response purposes to access the location and movement of any radioactive plume.

Under the Clean Air Act, the U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS), which specify maximum concentrations for carbon monoxide (CO), particulate matter with aerodynamic diameters of 10 microns or less (PM_{10}), particulate matter with aerodynamic diameters of 2.5 microns or less ($PM_{2.5}$), ozone, sulfur dioxide (SO_2), lead, and nitrogen dioxide (NO_2). Areas of the United States having air quality as good as or better than the NAAQS are designated by EPA as attainment areas. Areas having air quality that is worse than the NAAQS are designated by EPA as non-attainment areas. Those areas that were previously designated nonattainment and subsequently redesignated to attainment due to meeting the NAAQS are maintenance areas. States with maintenance areas are required to develop an air quality maintenance plan as an element of the State Implementation Plan.

A summary of the attainment status for SLO County is provided in Table 2.10-1. Ambient air quality in the County is generally good (i.e., within applicable ambient air quality standards), with the exception of ozone (O_3).

Meteorology information, as it relates to the analysis of severe accidents, is included in Attachment F of this Environmental Report.

2.11 HISTORIC AND ARCHAEOLOGICAL RESOURCES

2.11.1 AREA HISTORY IN BRIEF

San Luis Obispo County lies within the traditional ethnographic territory of the Northern Chumash. The Chumash were among the most populous and socially complex groups in all of native California. By the beginning of the Protohistoric Period, the Chumash were living in large villages along the Santa Barbara Channel coast, with less dense populations in the interior regions, on the Channel Islands, and in coastal areas north of Point Conception. Population density was unusually high for a nonagricultural group; some villages may have had as many as 1,000 inhabitants. Occupational specialization went beyond craft activities such as bead production to include politics, religion, and technology. Complex social and religious systems tied many villages together and regulated regional trade, procurement and redistribution of food and other resources, conflict, and other aspects of society. Leadership was hereditary, and some chiefs had influence over several villages, indicating a simple chiefdom level of social organization (References 98 and 115).

The Northern Chumash apparently were never as populous as their relatives in the Santa Barbara region, and archaeological research suggests societies less dependent on fishing (Reference 106). Local populations may have led a less sedentary lifestyle with a dietary focus on inland rather than coastal or maritime resources and greater reliance on logistic mobility than their southern neighbors (Reference 127). The Northern Chumash may not have attained the levels of social and political development of their southern counterparts, and the extent to which they participated in regional networks integrating social and economic activities remains to be clarified.

The historic occupation of this region began with the Mission Period. The Mission Period was ushered in by Gasper de Portolá, who camped at the mouth of the Santa Maria River in July 1769. The establishment of the Spanish Presidio in Santa Barbara and five Franciscan missions in Chumash territory significantly disrupted social, economic, and political organization. Introduction of domestic plants and animals as well as European wild grasses caused irreversible changes in the local environment. Native Californians had limited resistance to European diseases, which caused significant deaths among the Chumash.

Spanish occupation brought Chumash culture to the brink of extinction. Although people of Chumash ancestry still live in the region today and many strive to retain parts of their culture, the complex social system of the Chumash ended during the Mission Period (1769–1830). Larson et al. (1989) (Reference 128) suggest that climatic variability, prolonged droughts, and warmer sea-surface temperatures during this period forced the Chumash into the missions as a strategy to minimize economic and social risk. However, Price (2006) (Reference 120) argues that Mission agricultural yields were insufficient to support the native population, and the Northern Chumash continued to practice the full suite of traditional foodways well into the Mission period.

Following the Mexican Revolution of 1821, California became part of the Republic of Mexico. With independence, the Mexican government began to secularize the mission properties, a process that was concluded in 1833. The missions were converted into churches, and regional commissions were established to dispose of the properties and resettle the Indians affiliated with the missions. Mexican government policy was to grant mission properties and other unclaimed land to prominent citizens who were required to inhabit and develop properties. This period of California history, known as the Rancho Period, brought in a class of wealthy landowners who controlled the subsequent development of the state. The deterioration of relations between the United States and Mexico resulted in the Mexican War, which ended with Mexico relinquishing California to the United States under the Treaty of Guadalupe Hidalgo of 1848.

The political and economic unrest in California during the early and mid-1840s is evident in the Mexican government's conveyance of the *Cañada De Los Osos y Pecho y Islay*, a 32,431-acre land grant that includes the now PG&E-owned lands. In 1842, Governor Alvarado granted the *Cañada De Los Osos* to Victor Linares; one year later, Alvarado's successor as governor, Manuel Micheltorena, awarded the *Pecho y Islay* to Francisco Padillo. In 1845, Micheltorena was replaced by Pio Pico (Reference 123). In September of that year, Pico consolidated the two grants and issued them to Diego (James) Scott and Juan (John) Wilson. By 1850, Wilson became the sole proprietor of the *Cañada De Los Osos y Pecho y Islay*.

The Pecho y Islay Rancho (or Pecho Ranch) was likely used as pasture land. Although the eastern boundary of the ranch lay only 10-12 miles from the town of San Luis Obispo, the property was largely isolated and undeveloped. Until fairly recently, the Pecho Valley Road—which extends just north of the present DCPP site and on through Montana De Oro State Park, then eastward through the Los Osos Valley, and on towards San Luis Obispo—was the only land route between the ranch and the outside world.

The emergence of the dairy industry following the 1862-1864 drought attracted many northern Italian immigrants as well as Portuguese from the Azores Islands to San Luis Obispo County (Reference 116). Among these immigrants was Luigi Marre, native of Genoa, Italy. Marre leased the Pecho Ranch for 18 years, after which he bought 3,800 acres of the property. Marre's parcel lay south of Diablo Creek. The northern portion of the Pecho Ranch is associated with another prominent stockman in San Luis Obispo County, Alden Bradford Spooner, Jr., who leased a 6,500-acre swath extending from just north of Islay Creek to Diablo Creek in 1892 (Reference 118). That same year he built his ranch house, which today serves as the visitors' center for Montaña de Oro State Park.

Along with livestock, agriculture was part of the Spooner Ranch's economy from the very beginning. According to Ed Petersen, a resident on the northern PG&E-owned land, crops were grown primarily on the coastal terrace, while livestock grazed in the hills further inland (Reference 120). During the 1920s and 1930s, much of the coastal terrace, including the project area, was leased to Japanese farmers. The impact of

Asian farmers on the county's agricultural economy was considerable; by 1938, the market value of vegetable crops—led by peas, lettuce, and tomatoes—totaled just over $2.8 million, surpassing the $2.2 million combined figure for wheat, barley, and beans (Reference 105). The Japanese continued to farm the land until 1942, when they were involuntarily relocated to interment camps established during World War II under Executive Order 9066.

Oscar Field acquired the Spooner Ranch in 1942. In 1954 he sold the northern half of the ranch to Irene McAllister. Following financial troubles, the land passed into federal receivership and became part of the Montana de Oro State Park in 1965 (Reference 117). Eventually, Field gave up farming because of difficulties in tapping enough water to irrigate his crops. PG&E purchased the property and incorporated it into the the grounds of DCPP. In 1985, PG&E began commercial operation of DCPP.

2.11.2 INITIAL OPERATION

The Final Environmental Statement (FES) for operation of DCPP identified four sites in San Luis Obispo County listed on the National Register of Historic Places: the Dana Adobe in Nipomo, Caledonia Adobe in San Miguel, Mission San Miguel in San Miguel, and Hearst San Simeon State Historic Park, about 3 miles northeast of San Simeon (Reference 3). Since that time, some 30 additional buildings, structures, sites, and districts in San Luis Obispo County have been added to the National Register. Of these, only the *Rancho Cañada De Los Osos y Pecho y Islay* archaeological district is located within 6 miles of the plant; it encompasses much of the PG&E-owned land at DCPP.

Systematic archaeological research began in the early twentieth century. The first professional surveys in the DCPP area were performed by Arnold Pilling in the late 1940s. He surveyed the marine terraces from Avila Beach to Morro Bay and recorded sites CA-SLO-2 (SLO-2), CA-SLO-3, and CA-SLO-61 at the mouth of Diablo Creek (Reference 119). In addition he identified two other sites, CA-SLO-7 and CA-SLO-8, located northwest of Diablo Creek.

In 1966, State Archaeologist Francis Riddell conducted a survey of approximately 250 acres slated to be the future site of the DCPP. Riddell identified five archaeological sites in the area—Riddell Nos. 1, 2, 3, 4, and 5—but his report provides very little descriptive information concerning the sites, area surveyed, and method of survey (Reference 122). Although it is not stated in the report, CA-SLO-2 is the same as Riddell's No. 1 and CA-SLO-61 is Riddell's No. 2. Thus, as a result of Riddell's survey, two previously recorded sites were relocated and three new sites (Riddell Nos. 3, 4, and 5) were recorded. One of the new sites, Riddell No. 4 was assigned the designation CA-SLO-584 in 1966.

In 1968, Roberta Greenwood conducted extensive excavations at CA-SLO-2, CA-SLO-61, CA-SLO-584, and three other sites within the construction areas for the DCPP facilities and a proposed access road from the plant to Avila Beach. Excavation appears to have been restricted to the direct impact areas of proposed facilities or remaining portions of the sites which had not been disturbed by grading or construction.

The excavations at CA-SLO-2 revealed a rich midden deposit more than 3 m deep, and exposed a cemetery complex containing 54 inhumations (Reference 107). Due to grading for road construction, an additional six inhumations were recovered from the site in November of 1968 and six fragmentary inhumations were collected in June 1969. A total of 66 burials were exposed. Grave goods were associated with some of the burials. The burials recovered from these excavations were turned over to a local Native American group and were reported to have been reburied.

The artifact inventory from the site includes 2,885 stone, bone, wood, and shell artifacts including projectile points, blades, knives, choppers, scrapers, boring or drilling implements, and cores. Ground stone items include steatite bowls, bowl mortars, manos, milling stones, pestles, pitted stones, and charmstones. Numerous mammal, shell, and bird bone artifacts were recovered in addition to 1,607 shell beads. A few shards of unglazed brownware pottery also were collected. Three radiocarbon assays reported in the original site report suggested a nearly continuous occupation spanning close to 10,000 years, making CA-SLO-2 one of the oldest and most intensively occupied sites known from coastal California (References 103 and 104).

Greenwood also excavated at CA-SLO-61 along the bluff overlooking the coast, where she recovered 40 artifacts including a bowl mortar, pitted stones, a cobble pestle, a drill, and 21 scrapers. These materials are similar to those recovered from the upper levels of CA-SLO-2 and were assigned by Greenwood (Reference 107) to the same cultural complex. Much of CA-SLO-61 was destroyed during construction of DCPP, only a small remnant of the site remains.

CA-SLO-584 was also excavated by Greenwood (Reference 107). The site was located on a small flat on the south bank of Diablo Creek, now the site of the DCPP switchyard. Materials collected included 10 projectile points, leaf-shaped blades, scrapers, three bowl fragments, a hopper mortar fragment, a pestle, pitted cobbles, brownware shards, *Olivella* disks, and *Mytilus* and *Tivela* beads. Historic materials included five glass trade beads and one brass ring. In addition, three cupule boulders were located within the site boundaries. Based on cross-dating of artifact types similar to the upper levels of CA-SLO-2 and the occurrence of historic period artifacts, the site was associated with short-term, seasonal occupation by the late prehistoric and historic Chumash (Reference 107).

The last site examined during the 1968-69 investigations was Riddell Site 3, located at the southern tip of Diablo Cove. Greenwood (Reference 107) provides the following description of the work completed at the site:

> "It should be noted that one additional locale was described in the contract agreement but not excavated during the fieldwork described in this report. A light scatter of shell which appeared fresh and recent was on the

> surface in 1968, but test pits dug by shovel disclosed only a very shallow soil covering on the volcanic outcrop and no shell, chipping waste, or artifacts below the surface. In view of the total priorities, no systematic excavation was attempted."

In 1974, Robert Hoover realized the importance of the *Rancho Canada de los Osos y Pecho y Islay* area and nominated 15 sites to the National Register as an archaeological district; his nomination included CA-SLO-50, -51, -52, -53, -54, -55, -58, -63, -585, -682, -684, -686, -687, -688, and -689 (Reference 114). Following her 1978 survey of the area surrounding CA-SLO-2, Greenwood submitted a NRHP nomination for CA-SLO-2/3 and CA-SLO-8 to be included within the archaeological district (Reference 112).

2.11.3 PROTECTION MEASURES FOR CA-SLO-2

CA-SLO-2 suffered substantial damage during construction of DCPP. Although portions of the site may have been destroyed, portions of the site have also been preserved and protected since that time. The 1980 Archeological Resources Management Plan (ARMP) notes:

> "The central part of the terrace between Diablo Canyon and next drainage to the northwest has been subject to both grading and fill and was the area most extensively used in the past. The amount of resource loss in this area is unknown. On so deep a midden, however, disturbance has likely been limited to the upper levels. In addition, in the course of preparing for the construction of Units 1 and 2, the central portion of the terrace was used as a depositary for soil removed from the plant site. Based on a comparison of maps prepared in 1966 and 1971, there is as much as 25 feet of fill presently concealing and protecting the midden in the center of the site (Reference 111)."

The fill deposited over the central portion of CA-SLO-2 effectively caps what remained of the main archaeological deposit. Portions of the site, however, remain exposed around the edges of the fill cap.

Since the 1968 investigations, PG&E has instituted various procedures for the protection and management of CA-SLO-2. In 1980, an ARMP was incorporated into the DCPP operating license (Reference 111). The ARMP addressed fire protection and limited further surface alterations at the site by confining storage of materials to areas protected by fill, restricting traffic flow, and limiting maintenance of roads and existing utility lines to areas which have been previously disturbed. The site area has been fenced and warning signs are posted at entry points of road access to the site. Since November of 1983, photographs have been taken at regular intervals from 23 stations within the site in order to monitor any physical changes to the site caused by natural or other processes. The ARMP requires PG&E to complete annual monitoring of CA-SLO-2 to determine if there are impacts to the site. In the past 20 years, the annual site condition assessment monitoring of CA-SLO-2 has shown no project induced impacts to the site.

In addition to the cultural resource protection measures, PG&E has created a Diablo Canyon Stewardship Committee. A PG&E Cultural Resources Specialist sits on this committee, which reviews all activities on PG&E-owned lands.

2.11.4 RECENT STUDIES

In 1986, Holson reported on the unsurveyed portions the NRC license regulated area for DCPP (Reference 113). A total of six prehistoric sites were reported. Three new sites, CA-SLO-1161, CA-SLO-1162, and CA-SLO-1163, two of Riddell's sites, CA-SLO-1159 (Riddell 3) and CA-SLO-1160 (Riddell 5), and a new site form were prepared for CA-SLO-61.

In 1988, Wilcoxon conducted intensive background research and a pedestrian survey of the access road between the power plant's northern guard station and the gate at Montana de Oro State Park. He documented five sites, including CA-SLO-7, -8, -1196, -1197, and -1198 (Reference 126). Later that year Breschini and Haversat tested CA-SLO-7 and CA-SLO-8, and found both sites to be significant cultural resources (Reference 99).

More recent studies include a survey of the northern portion of the DCPP property in 1991 that resulted in the identification of 36 cultural resources within the 370 acre area referred to as the North Ranch (Reference 100), followed by more detailed documentation of four sites (CA-SLO-5, -6, -9, and 1197/H) (Reference 101). In 1992, an intensive archaeological survey of 420 acres in the south portion of the property, referred to as the South Ranch, resulted in the documentation of 41 sites including 16 previously unidentified resources (Reference 125).

In 2006 and 2007, a new NRHP nomination package was completed for the Rancho Canada de los Osos y Pecho y Islay Prehistoric Archaeological Site District. The new nomination updated and expanded the district to include approximately 9,000 acres of PG&E property on the coastal bluff between Coon Creek and the Port San Luis lighthouse; the number of resources included within the district was thus expanded from 17 to 84 (Reference 102). The grouping of Native American sites within the archaeological district includes major villages, long-term residences, short-term residences, locations, ideological sites, and quarry sites. Of particular importance is CA-SLO-2(/3), one of the oldest prehistoric village sites identified along the central coast of California (previous NRHP listing #75000477).

Most recently, 25 sites on the North Ranch and an additional 44 sites on the South Ranch were revisited. At that time, sites were rerecorded on the current California Department of Parks and Recreation cultural resource records (DPR 523), and site locations were recorded using state-of-the-art GPS technology (References 102 and 120). The current condition of each site was assessed, with particular attention to bluff erosion and the effects of grazing and agriculture. Marine shell samples also were collected from many of the sites to obtain additional radiocarbon dates. A PG&E archaeologist reported on an additional five sites in close proximity to the DCPP. Seven sites recorded at the north end of the property by INFOTEC Research in 1991 were not formally revisited, nor were the two historic sites without prehistoric components. One additional site, CA-SLO-688, originally nominated to the NRHP by Hoover, was also not revisited. Subsequently, each site is periodically revisited in an on-going program of site monitoring and condition management.

In 2008, a ‘hot spot’ survey was completed of the transmission lines and on PG&E property adjacent to DCPP. This field study consisted of reviewing areas that have not been surveyed in the past and appear to be sensitive for cultural resources. Additionally, visits to previous recorded cultural resources were completed to assess the condition of the sites and the adequacy of the site records. This field study is documented in the Cultural Resources Technical Report (Reference 121). No new cultural resources were identified during field work.

2.11.5 CURRENT STATUS

As of 2008, the National Register of Historic Places listed 30 locations in San Luis Obispo County, California (Reference 124). Of these 30 locations, one falls within a 6 mile (9.7 km) radius of DCPP (Figure 2.1-2): Rancho Cañada de Los Osos y Pecho y Islay, including CA-SLO-2. Additionally, the National Register of Historic Places listed 139 locations in all counties DCPP transmission lines cross (San Luis Obispo, Kern, Monterey, King, and Fresno Counties) (Reference 124). Of these 139 locations, only two fall within a 1.2-mile (2 km) radius of DCPP transmission lines (Figure 3.1-6). Two Historical Places listed on the National Register fall just outside of the 6 mile buffer and are directly adjacent to PG&E-owned lands, these include the Port San Luis Site and the San Luis Obispo Light Station located on Point San Luis. Table 2.11-1 lists the three National Register of Historic Places sites within six miles of DCPP or within 1.2 miles of the transmission lines (the study area).

The study area, as defined above, lies within San Luis Obispo, Monterey, Fresno, Kings, and Kern Counties. Additional records searches were therefore conducted at the Northwest Information Center at Sonoma State University, the Southern San Joaquin Valley Information Center at California State University, Bakersfield, and the Central Coastal Information Center at the University of California, Santa Barbara. The Information Centers are part of the California Historical Resources Information System. PG&E Records were also reviewed at this time to identify previously recorded or otherwise known cultural resources and previously recorded archaeological sites within 6 miles of DCPP or within 1.2 miles of the DCPP transmission lines. The record searches identified 636 prior cultural resource studies and 439 prehistoric and historical sites within the project area. Seventy-nine sites have been recommended or determined eligible for the National Register, eight sites have been recommended as not eligible, and the remaining sites have either not been evaluated or the status is unknown. Unevaluated sites or status unknown are treated as eligible until otherwise determined not eligible. Additional information is provided in the Cultural Resources Technical Report (Reference 121), which includes a bibliography of studies, maps depicting studies and sites, and a CD containing site records and a record of consultation.

2.12 KNOWN OR REASONABLY FORESEEABLE PROJECTS IN THE SITE VICINITY

As indicated on Figure 2.1-3, there are no urban areas or industrial development within the 6-mile radius of DCPP.

In 2003, Duke Energy LLC proposed a modernization and replacement project on the existing Morro Bay Power Plant site, approximately 10 miles north of DCPP. If the project is approved and implemented, two new generating units would replace the existing four fossil fuel boiler units. The replacement facility would include two 600 MW gas-fired and steam driven combined cycle units. In addition, the existing three 450-ft tall stacks would be replaced with four 145-ft tall stacks. The new combined cycle units would continue to use the existing once-through seawater cooling system which draws from Morro Bay and discharges into Estero Bay. Power from the combined cycle units would tie into the existing 230 kV PG&E transmission system at the Morro Bay Power Plant Switchyard. Thus, no new transmission lines would be constructed for the proposed project. Natural gas would be delivered by the existing PG&E pipeline and distribution system (Reference 129). Currently, the Morro Bay Power Plant is owned and operated by Dynegy. Dynegy continues to pursue the modernization and replacement project (Reference 130).

Construction and operation of the new plant should have no environmental impact on DCPP. PG&E is not aware of any other substantial existing or reasonably foreseeable industrial projects in the vicinity of DCPP.

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Table 2.2-1

PHYLOGENETIC LISTING OF INTERTIDAL (I) AND SUBTIDAL (S) MARINE ORGANISMS ASSOCIATED WITH THE DCPP COASTLINE (COMPILED FROM DCPP TEMP)

SCIENTIFIC NAME	FAMILY / TAXON	DISTRIBUTION
Chrysophyta (golden-brown algae)		
Chrysophyte unid.	Chrysophyta	I, S
diatom chains unid. (erect)	Chrysophyta	I, S
diatom film	Chrysophyta	I, S
Chlorophyta (green algae)		
Bryopsis corticulans	Bryopsidaceae	I, S
Bryopsis hypnoides	Bryopsidaceae	I, S
Chaetomorpha spp.	Cladophoraceae	I
Chlorophyta (blades, juv.)	Ulvaceae	I
Chlorophyta (filamentous, unid.)	Chlorophyta	I, S
Cladophora graminea	Cladophoraceae	I
Cladophora spp.	Cladophoraceae	I
Codium fragile	Codiaceae	I, S
Codium setchellii	Codiaceae	I
Derbesia marina (filamentous)	Derbesiaceae	I, S
Halicystis ovalis (=Derbesia marina)	Derbesiaceae	I
Spongomorpha/Acrosiphonia/Cladophora-	Cladophoraceae	I, S
Ulothrix spp.	Ulotrichaceae	I
Ulva linza	Ulvaceae	I
Ulva spp.	Ulvaceae	I, S
Phaeophyta (brown algae)		
Alaria marginata	Alariaceae	I
Analipus japonicus	Chordariaceae	I
brown filament erect	Phaeophyta	I
Coilodesme californica	Dictyosiphonaceae	S
Colpomenia peregrina	Scytosiphonaceae	I, S
Colpomenia spp.	Scytosiphonaceae	I, S
Colpomenia/Leathesia/Soranthera spp.	Scytosiphonaceae	I
Cystoseira osmundacea	Cystoseiraceae	I, S
Desmarestia spp.	Desmarestiaceae	I, S
Desmarestia tabacoides	Desmarestiaceae	I, S
Dictyoneurum californicum	Lessoniaceae	I, S
Ectocarpales	Ectocarpaceae	I, S
Egregia menziesii	Alariaceae	I, S
Endarachne/Petalonia	Scytosiphonaceae	I, S
Fucaceae unid.	Fucaceae	I
Fucus gardneri	Fucaceae	I
Halorhipis winstonii	Punctariaceae	I
Haplogloia andersonii	Chordariaceae	I, S
Hesperophycus californicus	Fucaceae	I
Laminaria ephemera	Laminariaceae	S
Laminaria setchellii	Laminariaceae	I, S
Laminariales unid.	Laminariaceae	I, S
Leathesia difformis	Corynophlaeaceae	I
Macrocystis spp.	Lessoniaceae	I, S
Nereocystis luetkeana	Lessoniaceae	I, S
Pelvetia/Pelvetiopsis	Fucaceae	I
Pelvetiopsis limitata	Fucaceae	I

Table 2.2-1

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Petrospongium rugosum	Corynophlaeaceae	I
Phaeostrophion irregulare	Dictyosiphonaceae	I, S
Pterygophora californica	Alariaceae	S
Ralfsia spp.	Ralfsiaceae	I
Rosenvingea floridana	Scytosiphonaceae	I
Sargassum muticum	Cystoseiraceae	I
Scytosiphon dotyi	Scytosiphonaceae	I
Scytosiphon lomentaria	Scytosiphonaceae	I
Scytosiphon spp.	Scytosiphonaceae	I
Silvetia compressa	Fucaceae	I
Soranthera ulvoidea	Punctariaceae	I
Rhodophyta (red algae)		
Acrosorium uncinatum	Delesseriaceae	I, S
Ahnfeltiopsis leptophylla	Phyllophoraceae	I, S
Ahnfeltiopsis linearis	Phyllophoraceae	I, S
Ahnfeltiopsis spp.	Phyllophoraceae	S
Amplisiphonia pacifica	Rhodomelaceae	S
Anisocladella pacifica	Delesseriaceae	S
Antithamnion densum	Ceramiaceae	S
Antithamnion spp.	Ceramiaceae	I, S
Antithamnion/Platythamnion spp.	Ceramiaceae	I, S
Antithamnionella pacifica	Ceramiaceae	S
Bangia fusco-purpurea	Bangiaceae	I
Bossiella plumosa	Corallinaceae	I
Bossiella schmittii	Corallinaceae	S
Bossiella spp.	Corallinaceae	I, S
Botryocladia pseudodichotoma	Rhodymeniaceae	S
Branchioglossum bipinnatifidum	Delesseriaceae	S
Calliarthron spp.	Corallinaceae	I, S
Calliarthron/Bossiella spp.	Corallinaceae	I, S
Callithamnion acutum	Ceramiaceae	I
Callithamnion biseriatum	Ceramiaceae	S
Callithamnion pikeanum	Ceramiaceae	I, S
Callithamnion rupicola	Ceramiaceae	I
Callophyllis crenulata	Kallymeniaceae	S
Callophyllis firma	Kallymeniaceae	I, S
Callophyllis flabellulata	Kallymeniaceae	I, S
Callophyllis spp.	Kallymeniaceae	I, S
Callophyllis violacea	Kallymeniaceae	I, S
Centroceras clavulatum	Ceramiaceae	I, S
Ceramium eatonianum	Ceramiaceae	I
Ceramium spp.	Ceramiaceae	I, S
Chondracanthus canaliculatus	Gigartinaceae	I, S
Chondracanthus corymbiferus	Gigartinaceae	I, S
Chondracanthus harveyanus	Gigartinaceae	I, S
Chondracanthus spinosus	Gigartinaceae	I, S
Chondracanthus volans	Gigartinaceae	I
Chondria decipiens	Rhodomelaceae	I, S
Clathromorphum parcum	Corallinaceae	I, S
Corallina officinalis	Corallinaceae	I, S
Corallina spp.	Corallinaceae	I, S
Corallina vancouveriensis	Corallinaceae	I, S

Table 2.2-1 Sheet 3 of 16

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
coralline crust	Corallinaceae	I, S
Cryptopleura lobulifera	Delesseriaceae	I, S
Cryptopleura ruprechtiana	Delesseriaceae	I, S
Cryptopleura spp.	Delesseriaceae	I, S
Cryptopleura violacea	Delesseriaceae	I, S
Cryptosiphonia woodii	Dumontiaceae	I
Cumagloia andersonii	Helminthocladiaceae	I
Delesseria decipiens	Delesseriaceae	S
Delesseriacea	Delesseriaceae	I, S
Dilsea californica	Dumontiaceae	I
Endocladia muricata	Endocladiaceae	I
Erythrophyllum delesserioides	Kallymeniaceae	I, S
Farlowia compressa	Dumontiaceae	I, S
Farlowia mollis	Dumontiaceae	I, S
Farlowia spp.	Dumontiaceae	I, S
Fauchea laciniata	Rhodymeniaceae	S
Fauchea spp.	Rhodymeniaceae	I, S
Fryeella gardneri	Rhodymeniaceae	S
Gastroclonium subarticulatum	Champiaceae	I, S
Gelidium coulteri	Gelidiaceae	I, S
Gelidium purpurascens	Gelidiaceae	S
Gelidium pusillum	Gelidiaceae	I
Gelidium robustum	Gelidiaceae	I, S
Gelidium spp.	Gelidiaceae	I, S
Gloiosiphonia californica	Gloiosiphoniaceae	I, S
Gracilariopsis lemaneiformis	Gracilariaceae	I, S
Grateloupia doryphora	Cryptonemiaceae	I, S
Grateloupia setchellii	Cryptonemiaceae	I
Grateloupia spp.	Cryptonemiaceae	I
Griffithsia pacifica	Ceramiaceae	S
Gymnogongrus chiton	Phyllophoraceae	I
Halosaccion americanum	Rhodymeniaceae	I
Halymenia schizymenioides	Cryptonemiaceae	I, S
Halymenia spp.	Cryptonemiaceae	I, S
Herposiphonia verticillata	Rhodomelaceae	I
Hymenena flabelligera	Delesseriaceae	I, S
Hymenena multiloba	Delesseriaceae	I
Hymenena spp.	Delesseriaceae	I, S
Janczewskia gardneri	Rhodomelaceae	I
Kallymenia spp.	Cryptonemiaceae	S
Maripelta rotata	Rhodymeniaceae	S
Mastocarpus jardinii	Gigartinaceae	I
Mastocarpus papillatus	Gigartinaceae	I, S
Mazzaella affinis	Gigartinaceae	I, S
Mazzaella californicum	Gigartinaceae	I
Mazzaella flaccida	Gigartinaceae	I, S
Mazzaella heterocarpa	Gigartinaceae	I, S
Mazzaella leptorhynchos	Gigartinaceae	I, S
Mazzaella lilacina	Gigartinaceae	I, S
Mazzaella linearis	Gigartinaceae	I
Mazzaella rosea	Gigartinaceae	I, S
Mazzaella spp.	Gigartinaceae	I, S
Mazzaella volans	Gigartinaceae	I

Table 2.2-1

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Melobesia mediocris	Corallinaceae	I, S
Membranoptera platyphylla	Delesseriaceae	S
Membranoptera spp.	Delesseriaceae	S
Membranoptera tenuis	Delesseriaceae	S
Membranoptera/Branchioglossum	Delesseriaceae	S
Microcladia borealis	Ceramiaceae	I, S
Microcladia californica	Ceramiaceae	I
Microcladia coulteri	Ceramiaceae	I, S
Microcladia spp.	Ceramiaceae	I, S
Nemalion helminthoides	Helminthocladiaceae	I
Neoptilota densa	Ceramiaceae	I, S
Neoptilota hypnoides	Ceramiaceae	I, S
Neoptilota spp.	Ceramiaceae	S
Neorhodomela larix	Rhodomelaceae	I
Nienburgia andersoniana	Delesseriaceae	I, S
Nitophyllum northii	Delesseriaceae	S
non-coralline crust	Rhodophyta	I, S
Odonthalia floccosa	Rhodomelaceae	I
Odonthalia washingtoniensis	Rhodomelaceae	S
Opuntiella californica	Solieriaceae	S
Osmundea blinksii	Rhodomelaceae	I
Osmundea spectabilis	Rhodomelaceae	I, S
Osmundea spp.	Rhodomelaceae	I, S
Phycodrys isabelliae	Delesseriaceae	S
Phycodrys setchellii	Delesseriaceae	I, S
Phycodrys spp.	Delesseriaceae	S
Phyllospadix scouleri	Magnoliophyta	I, S
Phyllospadix spp.	Magnoliophyta	I, S
Pikea californica	Dumontiaceae	I, S
Pikea robusta	Dumontiaceae	S
Pikea spp.	Dumontiaceae	I, S
Pleonosporium spp.	Ceramiaceae	I
Pleonosporium squarrulosum	Ceramiaceae	S
Plocamium cartilagineum	Plocamiaceae	I, S
Plocamium spp.	Plocamiaceae	I, S
Plocamium violaceum	Plocamiaceae	I, S
Polyneura latissima	Delesseriaceae	I, S
Polysiphonia hendryi	Rhodomelaceae	I
Polysiphonia paniculata	Rhodomelaceae	I
Polysiphonia spp.	Rhodomelaceae	I, S
Porphyra nereocystis	Bangiaceae	S
Porphyra occidentalis	Bangiaceae	S
Porphyra spp.	Bangiaceae	I, S
Prionitis australis	Cryptonemiaceae	I, S
Prionitis lanceolata	Cryptonemiaceae	I, S
Prionitis lyallii	Cryptonemiaceae	I, S
Prionitis spp.	Cryptonemiaceae	I, S
Pterochondria woodii var. *woodii*	Rhodomelaceae	S
Pterocladia caloglossoides	Gelidiaceae	I, S
Pterocladia media	Gelidiaceae	S
Pterosiphonia baileyi	Rhodomelaceae	I, S
Pterosiphonia bipinnata	Rhodomelaceae	I
Pterosiphonia dendroidea	Rhodomelaceae	I, S

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Pterosiphonia spp.	Rhodomelaceae	I, S
Pterothamnion heteromorphum	Ceramiaceae	S
Pterothamnion spp.	Ceramiaceae	S
Pterothamnion villosum	Ceramiaceae	I, S
Rhodoptilum plumosum	Dasyaceae	S
Rhodymenia californica	Rhodymeniaceae	S
Rhodymenia callophyllidoides	Rhodymeniaceae	S
Rhodymenia pacifica	Rhodymeniaceae	I, S
Rhodymenia spp.	Rhodymeniaceae	I, S
Sarcodiotheca gaudichaudii	Solieriaceae	I, S
Schizymenia epiphytica	Nemastomataceae	I, S
Schizymenia pacifica	Nemastomataceae	I, S
Schizymenia spp.	Nemastomataceae	S
Scinaia confusa	Chaetangiaceae	I, S
Scinaia johnstoniae	Chaetangiaceae	I
Smithora naiadum	Erythropeltidaceae	I, S
Stenogramme interrupta	Phyllophoraceae	S
Tiffaniella snyderae	Ceramiaceae	S
Weeksia digitata	Dumontiaceae	S
Weeksia reticulata	Dumontiaceae	S
Weeksia spp.	Dumontiaceae	S
Porifera (sponges)		
Acanthancora cyanocrypta	Demospongiae	S
Acarnus erithacus	Demospongiae	I, S
Antho karykina	Demospongiae	I
Clathria pseudonapya	Demospongiae	I
Cliona spp.	Demospongiae	S
Craniella arb	Demospongiae	S
Haliclona spp.	Demospongiae	I, S
Leucandra heathi	Calcarea	I, S
Leucetta losangelensis	Calcarea	I, S
Leucilla nuttingi	Calcarea	I, S
Leucosolenia eleanor	Calcarea	I, S
Leucosolenia spp.	Calcarea	I, S
Porifera unid. (encrusting)	Porifera	I, S
Tethya californiana	Demospongiae	I, S
Cnidaria (hydroids, anemones)		
Abietinaria/Sertularella/Sertularia	Hydrozoa	I, S
Aglaophenia spp.	Hydrozoa	I, S
Anthopleura artemisia	Anthozoa	I, S
Anthopleura elegantissima	Anthozoa	I, S
Anthopleura sola	Anthozoa	I
Anthopleura xanthogrammica	Anthozoa	I, S
Anthozoa unid.	Anthozoa	I, S
Balanophyllia elegans	Anthozoa	I, S
Cactosoma arenaria	Anthozoa	I, S
Ceriantharia unid.	Anthozoa	S
Clavularia spp.	Anthozoa	S
Corynactis californica	Anthozoa	I, S
Diadumene spp.	Anthozoa	S
Epiactis prolifera	Anthozoa	I, S
Halcampa decemtentaculata	Anthozoa	I, S
hydroid, epiphytic	Hydrozoa	S

Table 2.2-1

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
hydroid, thecate	Hydrozoa	I, S
Hydroidolina unid.	Hydrozoa	I, S
Manania spp.	Scyphozoa	S
Obelia spp.	Hydrozoa	I, S
Paracyathus stearnsii	Anthozoa	S
Plumularia spp.	Hydrozoa	S
Stylantheca porphyra	Hydrozoa	I
Stylantheca spp.	Hydrozoa	I
Tubularia spp.	Hydrozoa	S
Urticina coriacea	Anthozoa	I, S
Urticina felina	Anthozoa	I, S
Urticina lofotensis	Anthozoa	I, S
Urticina spp.	Anthozoa	I, S
Platyhelminthes (flatworms)		
Alloioplana californica	Platyhelminthes	I
Eurylepta californica	Platyhelminthes	I, S
Eurylepta spp.	Platyhelminthes	I
Notoplana spp.	Platyhelminthes	I
Platyhelminthes unid.	Platyhelminthes	I, S
Prostheceraeus bellostriatus	Platyhelminthes	S
Pseudoceros montereyensis	Platyhelminthes	S
Stylochus franciscanus	Platyhelminthes	I
Stylochus spp.	Platyhelminthes	I, S
Nemertea (ribbon worms)		
Amphiporus imparispinosus	Nemertea	I
Micrura verrilli	Nemertea	S
Nemertea unid.	Nemertea	I, S
Paranemertes peregrina	Nemertea	I
Tubulanus polymorphus	Nemertea	I, S
Tubulanus sexlineatus	Nemertea	I, S
Polychaeta (segmented worms)		
Aphrodita spp.	Aphroditidae	I, S
Chaetopteridae unid.	Chaetopteridae	I
Chaetopterus variopedatus	Chaetopteridae	I
Cirratulidae/Terebellidae unid.	Polychaeta	I, S
Diopatra ornata	Onuphidae	I, S
Dodecaceria fewkesi	Cirratulidae	I, S
Eudistylia polymorpha	Sabellidae	I, S
Flabelliderma essenbergae	Nereidae	S
Halosydna brevisetosa	Polynoidae	I
Hydroides elegans	Serpulidae	S
Myxicola infundibulum	Sabellidae	I, S
Nereididae unid.	Nereidae	I, S
Nereis grubei	Nereidae	I
Nereis pelagica	Nereidae	I
Phragmatopoma californica	Sabellariidae	I, S
Phyllochaetopterus prolifica	Chaetopteridae	I, S
Pista pacifica	Terebellidae	I
Pista spp.	Terebellidae	I, S
Polychaeta unid.	Polychaeta	I, S
Polynoidae unid.	Polynoidae	I, S
Sabellidae unid.	Sabellidae	I, S
Salmacina tribranchiata	Serpulidae	I, S

Table 2.2-1

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Serpula vermicularis	Serpulidae	I, S
Serpulidae unid.	Serpulidae	I, S
Spiochaetopterus costarum	Chaetopteridae	I, S
Spionidae unid.	Spionidae	I
Spirobranchus spinosus	Serpulidae	I, S
Spirorbidae unid.	Serpulidae	I
Spirorbis spp.	Serpulidae	I, S
Streblosoma crassibranchia	Terebellidae	I
Terebellidae unid.	Terebellidae	I, S
Mollusca - Gastropoda (snails)		
Acanthinucella punctulata	Neogastropoda	I
Acanthinucella spirata	Neogastropoda	I
Acanthinucella spp.	Neogastropoda	I
Acmaea mitra	Archaeogastropoda	I, S
Acmaea spp.	Archaeogastropoda	I
Alia carinata	Neogastropoda	I, S
Alia spp.	Neogastropoda	I, S
Alia tuberosa	Neogastropoda	I
Amphissa columbiana	Neogastropoda	S
Amphissa spp.	Neogastropoda	I, S
Amphissa versicolor	Neogastropoda	I, S
Aptyxis luteopictus	Neogastropoda	I, S
Barleeia acuta	Mesogastropoda	I
Barleeia spp.	Mesogastropoda	I, S
Bittium eschrichtii	Mesogastropoda	I, S
Bittium spp.	Mesogastropoda	I, S
Callianax biplicata	Olividae	S
Calliostoma annulatum	Archaeogastropoda	I, S
Calliostoma canaliculatum	Archaeogastropoda	I, S
Calliostoma gloriosum	Archaeogastropoda	S
Calliostoma ligatum	Archaeogastropoda	I, S
Calliostoma spp.	Archaeogastropoda	I, S
Calliostoma supragranosum	Archaeogastropoda	I, S
Ceratostoma foliatum	Neogastropoda	S
Chlorostoma brunnea	Archaeogastropoda	I, S
Chlorostoma funebralis	Archaeogastropoda	I
Chlorostoma montereyi	Archaeogastropoda	I, S
Chlorostoma spp.	Archaeogastropoda	I
Conus californicus	Conidae	I, S
Crepidula spp.	Mesogastropoda	I, S
Dendropoma lituella	Mesogastropoda	I, S
Dendropoma spp.	Mesogastropoda	I, S
Diodora aspera	Archaeogastropoda	I, S
Diodora spp.	Archaeogastropoda	I, S
Discurria insessa	Archaeogastropoda	I, S
Erato spp.	Mesogastropoda	I, S
Erato vitellina	Mesogastropoda	I, S
Eulithidium compta	Archaeogastropoda	S
Eulithidium pulloides	Archaeogastropoda	I, S
Eulithidium spp.	Archaeogastropoda	I, S
Fissurella volcano	Archaeogastropoda	I, S
Fissurellidea bimaculata	Archaeogastropoda	I, S
Garnotia adunca	Mesogastropoda	I, S

Table 2.2-1

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Granulina margaritula	Neogastropoda	I, S
Haliotis cracherodii	Archaeogastropoda	I
Haliotis rufescens	Archaeogastropoda	I, S
Haliotis spp.	Archaeogastropoda	I, S
Hima mendicus	Neogastropoda	I, S
Hima spp.	Neogastropoda	I
Hipponix spp.	Mesogastropoda	I, S
Homalopoma baculum	Archaeogastropoda	I
Homalopoma luridum	Archaeogastropoda	I
Homalopoma spp.	Archaeogastropoda	I, S
Kelletia kelletii	Neogastropoda	I, S
Lacuna marmorata	Mesogastropoda	I, S
Lacuna spp.	Mesogastropoda	I, S
Lamellaria diegoensis	Mesogastropoda	I, S
Lirabuccinum dirum	Neogastropoda	S
Lirularia spp.	Archaeogastropoda	S
Littorina keenae	Mesogastropoda	I
Littorina scutulata	Mesogastropoda	I
Littorina spp.	Mesogastropoda	I
Lottia asmi	Archaeogastropoda	I, S
Lottia digitalis	Archaeogastropoda	I
Lottia fenestrata	Archaeogastropoda	I, S
Lottia gigantea	Archaeogastropoda	I
Lottia instabilis	Archaeogastropoda	I, S
Lottia limatula	Archaeogastropoda	I
Lottia ochracea	Archaeogastropoda	I, S
Lottia paleacea	Archaeogastropoda	I, S
Lottia pelta	Archaeogastropoda	I
Lottia persona	Archaeogastropoda	I, S
Lottia scabra	Archaeogastropoda	I
Lottia scutum	Archaeogastropoda	I
Lottia spp.	Archaeogastropoda	I, S
Lottia strigatella	Archaeogastropoda	I, S
Lottiidae unid.	Archaeogastropoda	I, S
Maxwellia santarosana	Neogastropoda	S
Megathura crenulata	Archaeogastropoda	I, S
Melanella thersites	Mesogastropoda	S
Nitidiscala tinctum	Mesogastropoda	I, S
Nitiscala spp.	Mesogastropoda	I, S
Norrisia norrisi	Archaeogastropoda	S
Nucella analoga	Neogastropoda	I
Nucella emarginata	Neogastropoda	I
Nucella spp.	Neogastropoda	I
Ocenebrina atropurpurea	Neogastropoda	I
Ocenebrina circumtexta	Neogastropoda	I, S
Ocenebrina foveolata	Neogastropoda	I, S
Ocenebrina interfossa	Neogastropoda	I, S
Ocenebrina lurida	Neogastropoda	I, S
Ocenebrina spp.	Neogastropoda	I, S
Odostomia spp.	Neogastropoda	I, S
Opalia funiculata	Mesogastropoda	I
Opalia spp.	Mesogastropoda	I, S
Pomaulax gibberosa	Archaeogastropoda	I, S

Table 2.2-1

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Pomaulax undosa	Archaeogastropoda	S
Promartynia pulligo	Archaeogastropoda	I, S
Pseudomelatoma torosa	Neogastropoda	I, S
Rictaxis punctocaelatus	Neogastropoda	S
Searlesia/Amphissa spp.	Neogastropoda	I, S
Serpulorbis squamigerus	Mesogastropoda	I, S
Trimusculus reticulatus	Archaeogastropoda	I
Trivia californiana	Mesogastropoda	I, S
Trivia spp.	Mesogastropoda	S
Urosalpinx subangulata	Neogastropoda	I
Velutina velutina	Mesogastropoda	I
Mollusca - Opisthobranchs (sea slugs)		
Acanthodoris lutea	Nudibranchia	I, S
Acanthodoris rhodoceras	Nudibranchia	S
Aegires albopunctatus	Nudibranchia	I, S
Aeolidia papillosa	Nudibranchia	I, S
Aeolidiacea unid.	Nudibranchia	I, S
Aeolidiella oliviae	Nudibranchia	I, S
Aldisa sanguinea	Nudibranchia	I, S
Ancula pacifica	Nudibranchia	S
Aplysia californica	Aplysiidae	I, S
Aplysia vaccaria	Aplysiidae	S
Archidoris montereyensis	Nudibranchia	I, S
Babakina festiva	Nudibranchia	S
Berthella californica	Notaspidea	S
Cadlina flavomaculata	Nudibranchia	I, S
Cadlina luteomarginata	Nudibranchia	I, S
Cadlina modesta	Nudibranchia	S
Chromodoris macfarlandi	Nudibranchia	S
Dendrodoris spp.	Dendrodorididae	I, S
Dendronotus iris	Nudibranchia	I
Diaulula sandiegensis	Nudibranchia	I, S
Dirona albolineata	Nudibranchia	S
Doridacea unid.	Nudibranchia	I, S
Doriopsilla albopunctata	Nudibranchia	I, S
Doriopsilla gemela	Nudibranchia	S
Doto kya	Nudibranchia	I, S
Elysia hedgpethi	Sacoglossa	I
Flabellina iodinea	Nudibranchia	S
Flabellina spp.	Nudibranchia	I
Flabellina trilineata	Nudibranchia	I, S
Geitodoris heathi	Nudibranchia	S
Haminoea spp.	Cephalaspidea	I
Hancockia californica	Nudibranchia	S
Hermissenda crassicornis	Nudibranchia	I, S
Hopkinsia rosacea	Nudibranchia	I, S
Laila cockerelli	Nudibranchia	I, S
Melibe leonina	Nudibranchia	S
Navanax inermis	Cephalaspidea	I, S
Nudibranchia unid.	Nudibranchia	I
Onchidella borealis	Basommatophora	I
Peltodoris nobilis	Nudibranchia	I, S
Phidiana hiltoni	Nudibranchia	I, S

Table 2.2-1

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Rostanga pulchra	Nudibranchia	I, S
Triopha catalinae	Nudibranchia	I, S
Triopha maculata	Nudibranchia	I, S
Triopha spp.	Nudibranchia	I, S
Tritonia festiva	Nudibranchia	S
Williamia peltoides	Basommatophora	I, S
Mollusca - Polyplacophora (chitons)		
Callistochiton crassicostatus	Polyplacophora	S
Cryptochiton stelleri	Polyplacophora	I, S
Ischnochitonidae unid.	Polyplacophora	I, S
Katharina tunicata	Polyplacophora	I
Lepidochitona dentiens	Polyplacophora	I
Lepidochitona hartwegii	Polyplacophora	I
Lepidochitona spp.	Polyplacophora	I
Lepidozona cooperi	Polyplacophora	I, S
Lepidozona mertensii	Polyplacophora	I
Lepidozona spp.	Polyplacophora	I, S
Mopalia ciliata	Polyplacophora	I, S
Mopalia hindsii	Polyplacophora	S
Mopalia lignosa	Polyplacophora	I, S
Mopalia muscosa	Polyplacophora	I, S
Mopalia spp.	Polyplacophora	I, S
Nuttallina californica	Polyplacophora	I
Nuttallina spp.	Polyplacophora	I
Placiphorella velata	Polyplacophora	I, S
Polyplacophora unid.	Polyplacophora	I, S
Stenoplax fallax	Polyplacophora	I
Stenoplax heathiana	Polyplacophora	I, S
Stenoplax spp.	Polyplacophora	I, S
Tonicella lineata	Polyplacophora	I, S
Mollusca - Bivalvia (clams)		
Chama arcana	Bivalvia	I
Chama spp.	Bivalvia	I, S
Crassadoma gigantea	Bivalvia	I, S
Epilucina californica	Bivalvia	I
Gari californica	Bivalvia	I
Glans subquadrata	Bivalvia	I, S
Hiatella arctica	Bivalvia	I, S
Hiatella spp.	Bivalvia	I, S
Irusella lamellifer	Bivalvia	I, S
Kellia laperousii	Bivalvia	I
Limaria hemphilli	Bivalvia	S
Macoma spp.	Bivalvia	I
Modiolus spp.	Bivalvia	I, S
Musculus pygmaeus	Bivalvia	I
Mytilidae unid.	Bivalvia	I, S
Mytilimeria nuttalli	Bivalvia	I
Mytilus californianus	Bivalvia	I, S
Mytilus galloprovincialis	Bivalvia	I, S
Mytilus spp.	Bivalvia	I
Pelecypoda unid.	Bivalvia	I, S
Pholadidae unid.	Bivalvia	I, S
Pododesmus cepio	Bivalvia	I, S

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SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Pseudochama spp.	Bivalvia	I
Septifer bifurcatus	Bivalvia	I
Transennella spp.	Bivalvia	I
Transennella tantilla	Bivalvia	I
Mollusca - Cephalopoda (octopus)		
Octopus spp.	Octopodidae	I, S
Pycnogonida (sea spiders)		
Pycnogonida unid.	Pycnogonida	I, S
Crustacea (barnacles, copepods, isopods, amphipods, crabs, shrimps)		
Alpheidae unid.	Alpheidae	S
Alpheus clamator	Alpheidae	S
Alpheus spp.	Alpheidae	S
Anomura unid.	Anomura	I
Balanus aquila	Cirripedia	S
Balanus crenatus	Cirripedia	I
Balanus nubilus	Cirripedia	I, S
Balanus spp.	Cirripedia	I, S
Balanus/Tetraclita spp.	Cirripedia	I, S
Brachyura unid.	Brachyura	I, S
Cancer antennarius	Cancridae	I, S
Cancer anthonyi	Cancridae	I, S
Cancer branneri	Cancridae	I
Cancer jordani	Cancridae	I
Cancer productus	Cancridae	I
Cancer spp.	Cancridae	I, S
Candacia spp.	Copepoda	S
Chthamalus fissus	Cirripedia	I, S
Cirolana harfordi	Isopoda	I
Cirolanidae unid.	Isopoda	I
Cirripedia unid.	Cirripedia	I
Clausocalanus jobei	Copepoda	S
Crangon nigricauda	Crangonidae	I
Crangon spp.	Crangonidae	I, S
Crangon stylirostris	Crangonidae	S
Cryptolithodes sitchensis	Lithodidae	I, S
Decapoda unid.	Decapoda	I
Exosphaeroma inornata	Isopoda	I
Gammaridea unid.	Amphipoda	S
Grapsidae unid.	Grapsidae	I
Hemigrapsus nudus	Grapsidae	I
Hemigrapsus oregonensis	Grapsidae	I
Heptacarpus sitchensis	Hippolytidae	I
Heptacarpus spp.	Hippolytidae	I, S
Hippolytidae unid.	Hippolytidae	I, S
Idotea spp.	Isopoda	I, S
Idotea stenops	Isopoda	I
Idotea urotoma	Isopoda	I
Idotea wosnesenskii	Isopoda	I
Isopoda unid.	Isopoda	I, S
Lebbeus lagunae	Hippolytidae	S
Ligia occidentalis	Isopoda	I
Lophopanopeus leucomanus heathi	Xanthidae	I
Lophopanopeus spp.	Xanthidae	I, S

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SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Loxorhynchus crispatus	Majidae	I, S
Loxorhynchus spp.	Majidae	I, S
Majidae unid.	Majidae	I, S
Megabalanus californicus	Cirripedia	I, S
Mimulus foliatus	Majidae	I, S
Mitra idae	Majidae	I, S
Natantia unid.	Natantia	I, S
Pachycheles rudis	Porcellanidae	I
Pachycheles spp.	Porcellanidae	I, S
Pachygrapsus crassipes	Grapsidae	I
Pagurus spp.	Paguridae	I, S
Panulirus interruptus	Palinuridae	I
Paracerceis cordata	Isopoda	S
Paraxanthias taylori	Xanthidae	I, S
Petrolisthes cinctipes	Porcellanidae	I
Petrolisthes spp.	Porcellanidae	I, S
Pollicipes polymerus	Cirripedia	I
Porcellanidae unid.	Porcellanidae	I, S
Pugettia gracilis	Majidae	I
Pugettia producta	Majidae	I, S
Pugettia richii	Majidae	I, S
Pugettia spp.	Majidae	I, S
Scyra acutifrons	Majidae	S
Sphaeromatidae unid.	Isopoda	I, S
Spirontocaris spp.	Hippolytidae	S
Tetraclita rubescens	Cirripedia	I, S
Xanthidae unid.	Xanthidae	I, S
Sipuncula (peanut worms)		
Phascolosoma agassizii	Sipuncula	I, S
Sipuncula unid.	Sipuncula	I, S
Themiste pyroides	Sipuncula	I, S
Bryozoa (moss animals)		
Barentsia spp.	Entoprocta	S
bryozoa unid. (encrusting)	Bryozoa	I, S
bryozoa unid. (erect)	Bryozoa	I, S
bryozoa unid. (foliose)	Bryozoa	I, S
Entoprocta unid.	Entoprocta	I, S
Eurystomella bilabiata	Cheilostomata	I, S
Flustrellidra corniculata	Ctenostomata	I, S
Heteropora spp.	Cyclostomata	S
Hippodiplosia insculpta	Cheilostomata	I
Membranipora spp.	Cheilostomata	S
Microporella californica	Cheilostomata	I, S
Phidolopora pacifica	Cheilostomata	S
Phidolopora spp.	Cheilostomata	S
Tricellaria spp.	Cheilostomata	I, S
Echinodermata (sea stars, brittle stars, sea cucumbers, sea urchins)		
Amphiodia occidentalis	Ophiuroidea	I
Amphipholis spp.	Ophiuroidea	I
Amphipholis squamata	Ophiuroidea	I
Asteroidea unid.	Asteroidea	I, S
Cucumaria spp.	Holothuroidea	I, S
Dermasterias imbricata	Asteroidea	S

Table 2.2-1

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Eupentacta quinquesemita	Holothuroidea	I, S
Henricia leviuscula	Asteroidea	I, S
Holothuroidea unid.	Holothuroidea	I, S
Leptasterias hexactis	Asteroidea	I, S
Leptasterias spp.	Asteroidea	I, S
Lissothuria nutriens	Holothuroidea	I, S
Ophiactis simplex	Ophiuroidea	I, S
Ophioplocus esmarki	Ophiuroidea	I, S
Ophiopteris papillosa	Ophiuroidea	I
Ophiothrix spiculata	Ophiuroidea	I, S
Ophiothrix spp.	Ophiuroidea	I, S
Ophiuroidea unid.	Ophiuroidea	I, S
Orthasterias koehleri	Asteroidea	I, S
Pachythyone rubra	Holothuroidea	I
Parastichopus californicus	Holothuroidea	I, S
Parastichopus parvimensis	Holothuroidea	I, S
Patiria miniata	Asteroidea	I, S
Pisaster brevispinus	Asteroidea	S
Pisaster giganteus	Asteroidea	I, S
Pisaster ochraceus	Asteroidea	I, S
Psolus chitonoides	Holothuroidea	S
Pycnopodia helianthoides	Asteroidea	I, S
Strongylocentrotus franciscanus	Echinoidea	I, S
Strongylocentrotus purpuratus	Echinoidea	I, S
Stylasterias forreri	Asteroidea	S
Ascidiacea (sea squirts)		
Archidistoma psammion	Ascidiacea	I, S
Archidistoma spp.	Ascidiacea	I, S
Ascidia ceratodes	Ascidiacea	S
Ascidia spp.	Ascidiacea	S
Boltenia villosa	Ascidiacea	S
Chelyosoma productum	Ascidiacea	S
Chelyosoma spp.	Ascidiacea	S
Clavelina huntsmani	Ascidiacea	I, S
Cnemidocarpa finmarkiensis	Ascidiacea	S
Didemnum/Trididemnum spp.	Ascidiacea	S
Distaplia spp.	Ascidiacea	S
Euherdmania claviformis	Ascidiacea	S
Metandrocarpa taylori	Ascidiacea	I, S
Perophora annectens	Ascidiacea	S
Pycnoclavella stanleyi	Ascidiacea	S
Pyura haustor	Ascidiacea	I, S
Ritterella pulchra	Ascidiacea	S
Ritterella spp.	Ascidiacea	S
Styela montereyensis	Ascidiacea	I, S
Styela spp.	Ascidiacea	S
Synoicum spp.	Ascidiacea	S
tunicate, colonial unid. a (white)	Ascidiacea	I, S
tunicate, colonial unid. b (yellow)	Ascidiacea	S
tunicate, colonial unid. c (orange)	Ascidiacea	I, S
tunicate, solitary unid.	Ascidiacea	I, S
Chondrichthys (sharks, rays)		
Cephaloscyllium ventriosum	Chondrichthys	S

Table 2.2-1

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Myliobatis californica	Chondrichthys	S
Platyrhinoidis triseriata	Chondrichthys	S
Raja binoculata	Chondrichthys	S
Raja inornata	Chondrichthys	S
Raja spp.	Chondrichthys	S
Rhinobatos productus	Chondrichthys	S
Torpedo californica	Chondrichthys	S
Triakis semifasciata	Chondrichthys	S
Urolophus halleri	Chondrichthys	S
Osteichthys (bony fishes)		
Agonidae unid.	Agonidae	S
Anarrhichthys ocellatus	Anarhichadidae	S
Anoplarchus purpurescens	Stichaeidae	I, S
Apodichthys flavidus	Pholidae	I, S
Apodichthys fucorum	Pholidae	I, S
Artedius corallinus	Cottidae	I
Artedius lateralis	Cottidae	I, S
Artedius spp.	Cottidae	I, S
Atherinopsidae unid.	Atherinopsidae	I, S
Atherinopsis californiensis	Atherinopsidae	S
Atherinops affinis	Atherinopsidae	S
Atractoscion nobilis	Sciaenidae	S
Aulorhynchus flavidus	Gasterosteidae	S
Brachyistius frenatus	Embiotocidae	S
Cebidichthys violaceus	Stichaeidae	I, S
Chilara taylori	Ophidiidae	I, S
Chirolophis nugator	Stichaeidae	S
Chromis punctipinnis	Pomacentridae	S
Citharichthys spp.	Paralichthyidae	S
Citharichthys stigmaeus	Paralichthyidae	S
Clinocottus recalvus	Cottidae	I
Clinocottus spp.	Cottidae	I
Clinidae unid.	Clinidae	S
Cottidae unid.	Cottidae	I, S
Cymatogaster aggregata	Embiotocidae	S
Embiotoca jacksoni	Embiotocidae	S
Embiotoca lateralis	Embiotocidae	S
Embiotocidae unid.	Embiotocidae	S
Engraulis mordax	Engraulidae	S
Gibbonsia montereyensis	Clinidae	S
Gibbonsia metzi	Clinidae	I
Gibbonsia spp.	Clinidae	I, S
Girella nigricans	Kyphosidae	I, S
Gobiesocidae unid.	Gobiesocidae	I, S
Gobiesox maeandricus	Gobiesocidae	I, S
Halichoeres semicinctus	Labridae	S
Hermosilla azurea	Kyphosidae	S
Heterostichus rostratus	Clinidae	I, S
Hexagrammos decagrammus	Hexagrammidae	S
Hyperprosopon anale	Embiotocidae	S
Hyperprosopon argenteum	Embiotocidae	S
Hypsurus caryi	Embiotocidae	S
Hypsypops rubicundus	Pomacentridae	S

Table 2.2-1

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Jordania zonope	Cottidae	S
larval/post-larval fish unid.	Osteichthys	I, S
Lethops connectens	Gobiidae	S
Liparis mucosus	Liparidae	I
Liparis spp.	Liparidae	S
Medialuna californiensis	Kyphosidae	S
Micrometrus aurora	Embiotocidae	I
Micrometrus minimus	Embiotocidae	I
Morone saxatilis	Percichthyidae	S
Neoclinus stephensae	Chaenopsidae	S
Oligocottus maculosus	Cottidae	I
Oligocottus snyderi	Cottidae	I
Oligocottus spp.	Cottidae	I
Oncorhynchus tshawytscha	Salmonidae	S
Ophiodon elongatus	Hexagrammidae	S
Orthonopias triacis	Cottidae	S
Oxyjulis californica	Labridae	I, S
Oxylebius pictus	Hexagrammidae	S
Paralabrax clathratus	Serranidae	S
Paralichthyidae unid.	Paralichthyidae	S
Paralichthys californicus	Paralichthyidae	S
Phanerodon atripes	Embiotocidae	S
Phanerodon furcatus	Embiotocidae	S
Phanerodon spp.	Embiotocidae	S
Pholididae unid.	Pholidae	I, S
Pholididae/Stichaeidae unid.	Osteichthys	I, S
Platichthys stellatus	Pleuronectidae	S
Pleuronectidae unid.	Pleuronectidae	S
Pleuronichthys coenosus	Pleuronectidae	S
Porichthys notatus	Batrachoididae	I, S
Rathbunella hypoplecta	Bathymasteridae	S
Rhacochilus toxotes	Embiotocidae	S
Rhacochilus vacca	Embiotocidae	S
Rhinogobiops nicholsii	Gobiidae	S
Rimicola muscarum	Gobiesocidae	S
Rimicola spp.	Gobiesocidae	S
Sardinops sagax	Clupeidae	I, S
Sciaenidae unid.	Sciaenidae	S
Scomber japonicus	Scombridae	S
Scorpaena guttata	Scorpaenidae	S
Scorpaenichthys marmoratus	Cottidae	S
Scytalina cerdale	Scytalinidae	I
Sebastes atrovirens	Scorpaenidae	S
Sebastes auriculatus	Scorpaenidae	S
Sebastes carnatus	Scorpaenidae	S
Sebastes caurinus	Scorpaenidae	S
Sebastes chrysomelas	Scorpaenidae	S
Sebastes melanops	Scorpaenidae	S
Sebastes miniatus	Scorpaenidae	S
Sebastes mystinus	Scorpaenidae	S
Sebastes nebulosus	Scorpaenidae	S
Sebastes pinniger	Scorpaenidae	S
Sebastes rastrelliger	Scorpaenidae	S

Table 2.2-1

SCIENTIFIC NAME	FAMILY / TAXON	DIST.
Sebastes serranoides	Scorpaenidae	S
Sebastes serranoides/S. flavidus	Scorpaenidae	S
Sebastes spp.	Scorpaenidae	I, S
Semicossyphus pulcher	Labridae	S
Seriphus politus	Sciaenidae	S
Stichaeidae unid.	Stichaeidae	S
Syngnathus spp.	Syngnathidae	S
Trachurus symmetricus	Carangidae	S
Typhlogobius californiensis	Gobiidae	I
Ulvicola sanctaerosae	Pholidae	I
Xiphister atropurpureus	Stichaeidae	I
Xiphister mucosus	Stichaeidae	I
Xiphister spp.	Stichaeidae	I, S

Table 2.2-2

COMMON AND SCIENTIFIC NAMES OF NEAR-SHORE COMMERCIAL (C) AND RECREATIONAL (R) FISH AND INVERTEBRATES CAUGHT IN CENTRAL CALIFORNIA

COMMON NAME	SCIENTIFIC NAME	C	R
Invertebrates			
Clam, Pismo	*Tivela stultorum*		x
Crab, rock	*Cancer* spp.	x	x
Crab, shore	*Pachygrapsus crassipes*		x
Crab, shore	*Hemigrapsus* spp.		x
Limpet, owl	*Lottia gigantea*		x
Mussel, California	*Mytilus californianus*		x
Mussel, bay	*Mytilus galloprovincialis*		x
Octopus	*Octopus* spp.		x
Scallop, rock	*Crassadoma gigantea*		x
Sea cucumber	*Parastichopus* spp.	x	x
Shrimp, bay	*Crangon stylirostris*	x	x
Squid, market	*Loligo opalescens*	x	
Urchin, red sea	*Strongylocentrotus franciscanus*	x	x
Whelk, Kellet's	*Kelletia kelletii*	x	x
Fish			
Anchovy, northern	*Engraulis mordax*	x	
Bass, kelp	*Paralabrax clathratus*		x
Bass, striped	*Morone saxatilis*		x
Cabezon	*Scorpaenichthys marmoratus*	x	x
Flounder, starry	*Platichthys stellatus*	x	x
Greenling, kelp	*Hexagrammos decagrammus*	x	x
Halfmoon	*Medialuna californiensis*		x
Halibut, California	*Paralichthys californicus*	x	x
Jacksmelt	*Atherinops californiensis*	x	x
Lingcod	*Ophiodon elongatus*	x	x
Mackerel, jack	*Trachurus symmetricus*	x	x
Midshipman, plainfin	*Porichthys notatus*		x
Monkeyface-eel	*Cebidichthys violaceus*	x	x
Opaleye	*Girella nigricans*		x
Ray, bat	*Myliobatis californica*	x	x
Rockfish, black	*Sebastes melanops*		x
Rockfish, black-and-yellow	*Sebastes chrysomelas*	x	x
Rockfish, blue	*Sebastes mystinus*		x
Rockfish, bocaccio	*Sebastes paucispinis*		x
Rockfish, gopher	*Sebastes carnatus*	x	x
Rockfish, grass	*Sebastes rastrelliger*	x	x
Rockfish, kelp	*Sebastes atrovirens*		x
Rockfish, olive	*Sebastes serranoides*		x
Rockfish, vermilion	*Sebastes miniatus*	x	x
Rockfish, yellowtail	*Sebastes flavidus*	x	x
Salmon, Chinook	*Oncorhynchus tshawytscha*	x	x
Sanddab, Pacific	*Citharichthys sordidus*	x	x
Sardine, Pacific	*Sardinops sagax*	x	x
Seabass, white	*Atractoscion nobilis*	x	x
Shark, leopard	*Triakis semifasciata*	x	x

Table 2.2-2

COMMON NAME	SCIENTIFIC NAME	C	R
Shark, Pacific angel	*Squatina californica*	x	x
Sheephead, California	*Semicossyphus pulcher*	x	x
Surfperch, barred	*Amphistichus argenteus*	x	x
Surfperch, black	*Embiotoca jacksoni*		x
Surfperch, pile	*Rhacochilus vacca*		x
Surfperch, rainbow	*Hypsurus caryi*		x
Surfperch, rubberlip	*Rhacochilus toxotes*		x
Surfperch, shiner	*Cymatogaster aggregata*		x
Surfperch, striped	*Embiotoca lateralis*		x
Surfperch, white	*Phanerodon furcatus*	x	x
Topsmelt	*Atherinops affinis*	x	x
Turbot, C-O	*Pleuronichthys coenosus*	x	x

Table 2.5-1

LIST OF FEDERALLY THREATENED OR ENDANGERED SPECIES THAT MAY EXIST IN THE VICINITY OF DCPP.

Class	Species	Common Name	Status[1, 2]
Amphibians	Ambystoma califoniense	California tiger salamander	E
Amphibians	Ambystoma macrodactylum croceum	Salamander, Santa Cruz long-toed	E
Amphibians	Bufo microscaphus californicus	Toad, Arroyo southwestern	E
Amphibians	Rana aurora draytonii	California red-legged frog	T
Birds	Brachyramphus marmoratus marmora	Murrelet, marbled	T
Birds	Charadrius alexandrinus nivosus	Plover, western snowy	T
Birds	Charadrius montanus	Mountain plover	not listed
Birds	Empidonax traillii extimus	Flycatcher, southwestern willow	E
Birds	Gymnogyps californianus	Condor, California	E
Birds	Haliaeetus leucocephalus	Eagle, bald	delisted
Birds	Pelecanus occidentalis	Pelican, brown	FPD
Birds	Rallus longirostris levipes	Rail, light-footed clapper	E
Birds	Rallus longirostris obsoletus	Rail, California clapper	E
Birds	Sterna antillarum browni	Tern, least	E
Birds	Vireo bellii pusillus	Vireo, lest Bell's	E
Crustaceans	Branchinecta longiantenna	Fairy shrimp, longhorn	E
Crustaceans	Branchinecta lynchi	Fairy shrimp, vernal pool	T
Fishes	Eucyclogobius newberryi	Goby, tidewater	E
Fishes	Gasterosteus aculeatus Williamson	Stickleback, unarmored three spin	E
Fishes	Oncorhynchus mykiss	Steelhead trout	T
Insects	Euphilotes enoptes smithi	Butterfly, Smith's blue	E
Insects	Euproserpinus euterpe	Moth, Kern primrose sphinx	T
Mammals	Arctocephalus townsendi	Seal, Guadulupe fur	T
Mammals	Dipodomys heermanni	Kangaroo rat, Morro Bay	E
Mammals	Dipodomys ingens	Kangaroo rat, giant	E
Mammals	Dipodomys nitraloide	Kangaroo rat, Tipton	E
Mammals	Enhydra lutris nereis	Otter, Southern sea	T
Mammals	Sorex ornatus relictus	Buena Vista Lake ornate shrew	E
Mammals	Vulpes macrotis mutica	Fox, San Joaquin kit	E
Plants	Arabis hoffmannii	Rock-cress, Hoffmann's	E
Plants	Arctostaphylos confertiflora	Manzanita, Santa Rosa Island	E
Plants	Arctostaphylos morroensis	Manzanita, Morro	T
Plants	Arenaria paludicola	Marsh sandwort	E
Plants	Astragalus tener titi	Marsh sandwort	E
Plants	Berberis pinnata insularis	Barberry, island	E
Plants	Castilleja mollis	Paintbrush, soft-leaved	E

Table 2.5-1

Class	**Species**	**Common Name**	**Status[1, 2]**
Plants	Caulanthis californicus	California jewelflower	E
Plants	Chlorogalum purpureum	Amole, purple	T
Plants	Chorizante pungens pungens	Spineflower, Monterey	T
Plants	Chorizanthe robusta	Spineflower, Robust	E
Plants	Cirsium fontinale fontinale	Fountain thistle	E
Plants	Cirsium fontinale obispoense	Thistle, Chorro Creek bog	E
Plants	Cirsium loncholepis	Thistle, La Graciosa	E
Plants	Clarka speciosa immaculate	Clarkia, Pismo	E
Plants	Cordylanthus maritimus maritimus	Salt marsh bird’s beak	E
Plants	Cupressus goveniana goveniana	Cypress, Gowen	T
Plants	Dudleya cymosa marcescens	Dudleya, Marcescent	T
Plants	Dudleya nesiotica	Liveforever, Santa Cruz Island	T
Plants	Dudleya setchellii	Santa Clara Valley dudleya	E
Plants	Dudleya traskiae	Santa Barbara Island liveforever	E
Plants	Eremalche kernensis	Kern mallow	E
Plants	Eriastum hooveri	Hoover’s woolly-star	T
Plants	Eriodictyon altissimum	Mountain balm, Indian Knob	E
Plants	Eriodictyon capitatum	Yerba santa, Lompoc	E
Plants	Erysimum menziesii	Menzies’ wallflower	E
Plants	Galium buxifolium	Bedstraw, island	E
Plants	Gilia tenuiflora arenaria	Monterey gilia	E
Plants	Gilia tenuiflora hoffmannii	Gilia, Hoffmann’s	E
Plants	Hemizonia increscens villosa	Tarweed, Gaviota	E
Plants	Holocarpha macradenia	Tarweed, Santa Cruz	T
Plants	Lasthenia conjugens	Goldfields, Contra Costa	E
Plants	Layia carnosa	Beach layia	E
Plants	Lembertia congdonii	San Joaquin wooly-threads	E
Plants	Lupinus nipomensis	Lupine, Nipomo Mesa	E
Plants	Lupinus tidestromii	Clover lupine	E
Plants	Malacothamnus fasciculatus nesioticus	Bush-mallow, Santa Cruz Island	E
Plants	Malacothrix indecora	Malocothrix, Santa Cruz Island	E
Plants	Malacothrix squalida	Malocothrix, island	E
Plants	Navarretia leucocephala pauciflora	Navarretia, few-flowered	E
Plants	Navarretia leucocephala plieantha	Navarretia, many-flowered	E
Plants	Opuntia treleasei	Bakersfield cactus	E
Plants	Parvisedum leiocarpum	Stonecrop, Lake County	E
Plants	Phacelia insularis insularis	Phacelia northern island	E
Plants	Piperia yadonii	Piperia, Yadon’s	E
Plants	Potentilla hickmanii	Cinquefoil, Hickman’s	E

Table 2.5-1 Sheet 3 of 3

Class	Species	Common Name	Status[1, 2]
Plants	Rorippa gambellii	Gambel's watercress	E
Plants	Suaeda californica	Seablite, California	E
Plants	Thysanocarpus conchuliferus	Fringepod, Santa Cruz Island	E
Plants	Trifolium trichocalyx	Clover, Del Monte	E
Reptiles	Chelonia mydas	Turtle, green sea	T
Reptiles	Gambelia silus	Lizard, blunt-nosed leopard	E
Reptiles	Gopherus agassizii	Tortoise, desert	T
Reptiles	Lepidochelys olivacea	Turtle, olive ridley	T
Reptiles	Xantusia riversiana	Lizard, Island night	T
Snails	Helminthoglypta walkeriana	Snail, Morro shoulderband	E

Notes:
1. E: Endangered, T: Threatened, FPD: federal proposed for delisting (Feb. 2008)
2. The species' status was updated by PG&E in 2008.

Table 2.5-2 Sheet 1 of 6

SPECIAL-STATUS PLANT SPECIES WITH POTENTIAL TO OCCUR IN THE DCPP TRANSMISSION LINE CORRIDORS

Common Name/ Scientific Name	Status (Federal /State/CNPS)	Blooming Period	Project Quads[1] Containing Occurrence Records	Habitat Requirements
Hoover's bent grass *Agrostis hooveri*	-- / -- / 1B.2	Apr-Jul	Arroyo Grande NE Oceano Pismo Beach Port San Luis	•Chaparral •Cismontane woodland •Valley and foothill grassland/usually sandy •60 - 600 meters
oval-leaved snapdragon *Antirrhinum ovatum*	-- / -- / 4.2	May-Nov	Cholame Hills Cholame Valley	•Chaparral •Cismontane woodland •Pinyon and juniper woodland •Valley and foothill grassland/clay or gypsum/often alkaline •200 - 1000 meters Appears only in favorable years
Arroyo de la Cruz manzanita *Arctostaphylos cruzensis*	-- / -- / 1B.2	Dec-Mar	Morro Bay South Port San Luis	•Broadleafed upland forest •Coastal bluff scrub •Closed cone coniferous forest •Chaparral •Coastal scrub •Valley and foothill grassland/sandy •60 - 310 meters Known from fewer than twenty occurrences
Pecho manzanita *Arctostaphylos pechoensis*	-- / -- / 1B.2	Nov-Mar	Morro Bay South Pismo Beach Port San Luis San Luis Obispo	•Closed cone coniferous forest •Chaparral •Coastal scrub/siliceous shale •150 - 850 meters
Santa Margarita manzanita *Arctostaphylos pilosula*	-- / -- / 1B.2	Dec-Mar	Arroyo Grande NE Atascadero Nipomo Oceano Pismo Beach San Luis Obispo Tar Springs Ridge	•Closed cone coniferous forest •Chaparral •Cismontane woodland/shale •170 - 1100 meters
dacite manzanita *Arctostaphylos tomentosa* ssp. *daciticola*	-- / -- / 1B.1	Mar	Morro Bay South	•Chaparral •Cismontane woodland/dacite porphyry buttes •100 - 300 meters

[1] Quad - Short for quadrangle. A standard map size and scale used by the U.S. Geological Survey. Typically refers to a map sheet, 7.5 minute or 15 minute (latitude and longitude) series.

Table 2.5-2 Sheet 2 of 6

Common Name/ Scientific Name	Status (Federal /State/CNPS)	Blooming Period	Project Quads[1] Containing Occurrence Records	Habitat Requirements
Wells' manzanita *Arctostaphylos wellsii*	-- / -- / 1B.1	Dec-Apr	Arroyo Grande NE Atascadero Nipomo Oceano Pismo Beach Port San Luis Tar Springs Ridge	•Closed cone coniferous forest •Chaparral/sandstone •30 - 400 meters
Miles' milk-vetch *Astragalus didymocarpus* var. *milesianus*	-- / -- / 1B.2	Mar-Jun	Atascadero Morro Bay North Morro Bay South Nipomo San Luis Obispo	•Coastal scrub/clay •20 - 90 meters
heartscale *Atriplex cordulata*	-- / -- / 1B.2	Apr-Oct	Lokern Simmler West Elk Hills	•Chenopod scrub •Meadows and seeps •Valley and foothill grassland (sandy)/saline or alkaline •1 - 375 meters
Lost Hills crownscale *Atriplex vallicola*	-- / -- / 1B.2	Apr-Aug	Chimineas Ranch Lokern Reward Simmler West Elk Hills	•Chenopod scrub •Valley and foothill grassland •Vernal pools /alkaline •50 - 635 meters
La Panza mariposa-lily *Calochortus obispoensis*	-- / -- / 1B.2	May-Jul	Arroyo Grande NE Atascadero Morro Bay South Oceano Pismo Beach San Luis Obispo	•Chaparral •Coastal scrub •Valley and foothill grassland /often serpentinite •75 - 730 meters
San Luis Obispo sedge *Carex obispoensis*	-- / -- / 1B.2	Apr-Jun	Atascadero Morro Bay South San Luis Obispo	•Closed cone coniferous forest •Chaparral •Coastal prairie •Coastal scrub •Valley and foothill grassland/often serpentinite seeps •10 - 790 meters
San Luis Obispo owl's-clover *Castilleja densiflora* ssp. *obispoensis*	-- / -- / 1B.2	Apr	Arroyo Grande NE Morro Bay North Morro Bay South Oceano Pismo Beach Port San Luis San Luis Obispo	•Valley and foothill grassland /clay •10 - 400 meters
Congdon's tarplant *Centromadia parryi* ssp. *congdonii*	-- / -- / 1B.2	Jun-Nov	Pismo Beach San Luis Obispo	•Valley and foothill grassland (alkaline) •1 - 230 meters

Table 2.5-2

Common Name/ Scientific Name	Status (Federal /State/CNPS)	Blooming Period	Project Quads[1] Containing Occurrence Records	Habitat Requirements
Brewer's spineflower *Chorizanthe breweri*	-- / -- / 1B.3	May-Jul	Arroyo Grande NE Atascadero Morro Bay North Pismo Beach San Luis Obispo	•Closed cone coniferous forest •Chaparral •Cismontane woodland •Coastal scrub/ serpentinite/rocky or gravelly •45 - 800 meters Known from approximately twenty occurrences
straight-awned spineflower *Chorizanthe rectispina*	-- / -- / 1B.3	May-Jul	Arroyo Grande NE Atascadero Branch Mountain San Luis Obispo	•Chaparral •Cismontane woodland •Coastal scrub •200 - 1035 meters Known from approximately twenty occurrences.
San Luis Obispo fountain thistle *Cirsium fontinale* var. *obispoense*	FE / SE / 1B.2	Feb-Jul	Atascadero Morro Bay North Morro Bay South Pismo Beach San Luis Obispo	•Chaparral •Cismontane woodland/ serpentinite seeps •35 - 365 meters Known from approximately ten occurrences
Pismo clarkia *Clarkia speciosa* ssp. *immaculata*	FE / CR / 1B.1	Mar-May	Arroyo Grande NE Oceano Pismo Beach	•Pinyon and juniper woodland •Valley and foothill grassland •80 - 1220 meters Known from only five occurrences
recurved larkspur *Delphinium recurvatum*	-- / -- / 1B.2	Mar-May	Chimineas Ranch Garza Peak Guijarral Hills Lokern McKittrick Summit Simmler The Dark Hole West Elk Hills	•Chenopod scrub •Cismontane woodland •Valley and foothill grassland /alkaline •3 - 750 meters Many historical occurrences
Betty's dudleya *Dudleya abramsii* ssp. *bettinae*	-- / -- / 1B.2	May-Jul	Morro Bay North Morro Bay South San Luis Obispo	•Chaparral •Coastal scrub •Valley and foothill grassland/serpentinite, rocky •20 - 180 meters Known from fewer than ten occurrences
mouse-gray dudleya *Dudleya abramsii* ssp. *murina*	FE / -- / 1B.1	May-Jun	Arroyo Grande NE Morro Bay South Pismo Beach San Luis Obispo	•Chaparral •Coastal scrub/serpentinite •90 - 300 meters
Blochman's dudleya *Dudleya blochmaniae* ssp. *blochmaniae*	-- / -- / 1B.1	Apr-Jun	Morro Bay South Pismo Beach San Luis Obispo	•Coastal bluff scrub •Coastal scrub •Chaparral •Valley and foothill grassland /often clay or serpentinite, rocky •5 - 450 meters Known from fewer than twenty occurrences in CA

Table 2.5-2

Common Name/ Scientific Name	Status (Federal /State/CNPS)	Blooming Period	Project Quads[1] Containing Occurrence Records	Habitat Requirements
Kern mallow *Eremalche kernensis*	FE / -- / 1B.1	Mar-May	Belridge Lokern Reward West Elk Hills	•Chenopod scrub •Valley and foothill grassland •70 - 1000 meters
Hoover's eriastrum *Eriastrum hooveri*	Delisted / -- / 4.2	Mar-Jul	Buttonwillow Lokern West Elk Hills	•Chenopod scrub •Pinyon and juniper woodland •Valley and foothill grassland •600 - 800 meters Previously listed as threatened by USFWS, but delisted in 2003
Indian Knob mountainbalm *Eriodictyon altissimum*	FE / CE / 1B.1	Mar-Jun	Morro Bay South Pismo Beach	•Chaparral (maritime) •Cismontane woodland •Coastal scrub/ sandstone •80 - 270 meters Known from six occurrences in the Irish Hills and Indian Knob
Hoover's button-celery *Eryngium aristulatum* var. *hooveri*	-- / -- / 1B.1	Jul	Morro Bay South Pismo Beach San Luis Obispo	•Vernal pools •3 - 45 meters Almost all collections old; need information on extant occurrences
San Benito fritillary *Fritillaria viridea*	-- / -- / 1B.2	Mar-May	Morro Bay North Morro Bay South San Luis Obispo	•Chaparral (serpentinite) •150 - 185 meters Needs study; plants from Monterey Co. may be *F. ojaiensis*
mesa horkelia *Horkelia cuneata* ssp. *puberula*	-- / -- / 1B.1	Feb-Sep	Arroyo Grande NE Atascadero Pismo Beach Port San Luis San Luis Obispo	•Chaparral •Cismontane woodland •Coastal scrub/sandy or gravelly •70 - 810 meters Many historical occurrences extirpated
Jones' layia *Layia jonesii*	-- / -- / 1B.2	Mar-May	Morro Bay North Morro Bay South Pismo Beach San Luis Obispo	•Chaparral •Valley and foothill grassland /clay or serpentinite •5 - 400 meters
Jared's pepper-grass *Lepidium jaredii* ssp. *jaredii*	-- / -- / 1B.2	Mar-May	Chimineas Ranch Estrella	•Valley and foothill grassland (alkaline, adobe) •335 - 1005 meters Known only from near Soda Lake on the Carrizo Plain

Table 2.5-2

Common Name/ Scientific Name	Status (Federal /State/CNPS)	Blooming Period	Project Quads[1] Containing Occurrence Records	Habitat Requirements
San Luis Obispo County lupine *Lupinus ludovicianus*	-- / -- / 1B.2	Apr-Jul	Arroyo Grande NE Caldwell Mesa Pismo Beach Tar Springs Ridge	•Chaparral •Cismontane woodland/sandstone or sandy •50 - 525 meters Known from fewer than twenty occurrences
Santa Lucia bush-mallow *Malacothamnus palmeri* var. *palmeri*	-- / -- / 1B.2	May-Jul	Atascadero Morro Bay North Morro Bay South Templeton	•Chaparral (rocky) •60 - 360 meters
San Luis Obispo monardella *Monardella frutescens*	-- / -- / 1B.2	May-Sep	Morro Bay South Oceano	•Coastal dunes •Coastal scrub (sandy) •10 - 200 meters
Palmer's monardella *Monardella palmeri*	-- / -- / 1B.2	Jun-Aug	Atascadero Morro Bay South San Luis Obispo	•Chaparral •Cismontane woodland serpentinite •200 - 800 meters
San Joaquin woollythreads *Monolopia congdonii*	FE / -- / 1B.2	Feb-May	Avenal Belridge Buttonwillow Garza Peak Guijarral Hills Lokern	•Chenopod scrub •Valley and foothill grassland (sandy) •60 - 800 meters Approximately half of historical occurrences extirpated
Diablo Canyon blue grass *Poa diaboli*	-- / -- / 1B.2	Mar-Apr	Morro Bay South Port San Luis	•Closed-cone coniferous forest •Chaparral (mesic) •Cismontane woodland •Coastal scrub/shale; sometimes burned areas •120 - 400 meters Known from approximately five occurrences in the San Luis Range
adobe sanicle *Sanicula maritima*	-- / CR / 1B.1	Feb-May	Morro Bay South San Luis Obispo	•Chaparral •Coastal prairie •Meadows and seeps •Valley and foothill grassland/clay, serpentinite •30 - 240 meters Known from fewer than ten occurrences

Table 2.5-2

Common Name/ Scientific Name	Status (Federal /State/CNPS)	Blooming Period	Project Quads[1] Containing Occurrence Records	Habitat Requirements
black-flowered figwort *Scrophularia atrata*	-- / -- / 1B.2	Mar-Jul	Arroyo Grande NE Oceano Pismo Beach	•Closed-cone coniferous forest •Chaparral •Coastal dunes •Coastal scrub •Riparian scrub •10 - 500 meters
most beautiful jewel-flower *Streptanthus albidus* ssp. *peramoenus*	-- / -- / 1B.2	Apr-Sep	Atascadero Morro Bay South San Luis Obispo	•Chaparral •Cismontane woodland •Valley and foothill grassland /usually serpentinite •94 - 1000 meters

Federal
FE = Listed as Endangered under the federal Endangered Species Act
FT = Listed as Threatened under the federal Endangered Species Act
State
CE = Listed as endangered under the California Endangered Species Act
CT = Listed as threatened under the California Endangered Species Act
CR = Listed as Rare in California
CNPS
List 1B = Plants rare, threatened, or endangered in California and elsewhere
List 2 = Plants rare, threatened, or endangered in California, but more common elsewhere
Extension codes:
.3 = Not very endangered in California
.2 = Fairly endangered in California
.1 = Seriously endangered in California

Table 2.5-3

WILDLIFE SPECIES WITH POTENTIAL TO OCCUR IN THE DCPP TRANSMISSION LINE CORRIDORS

Common Name/ Scientific Name	Status (Federal/ State)	Project Quads[1] Containing Occurrence Records	Habitat Requirements
Nelson's antelope squirrel (*Ammospermophilus nelsoni*)	CT	Belridge Buttonwillow Chimineas Ranch Garza Peak Guijarral Hills Lokern McKittrick Summit Reward Shandon Simmler The Dark Hole West Elk Hills	• Requires arid, open shrublands and annual grassland habitats • Found at elevations of 200 to 1,200 feet
Silvery legless lizard (*Anniella pulchra pulchra)*	SC	Branch Mountain Morro Bay South San Luis Obispo	• Found in shrub habitats, as well as other habitats with sandy or loose soils. • Often found in soil at margins of shrubs.
Burrowing owl (*Athene cunicularia*)	SC	Avenal Buttonwillow Chimineas Ranch Guijarral Hills Lokern San Luis Obispo West Elk Hills	• Found in a variety of grassland and open shrubland habitats with low-growing vegetation. • Requires burrows made by other species, such as California ground squirrel, desert tortoise, badger, and kit fox.
Longhorn fairy shrimp (*Branchinecta longiantenna*)	FE	Chimineas Ranch	• Inhabits astatic grassland vernal pools. • Typically require small, clear-water depression in sandstone and clear-to-turbid clay/grass-bottomed pools in shallow swales. • Critical habitat has been designated.
Vernal pool fairy shrimp (*Branchinecta lynchi*)	FT	Branch Mountain Estrella Pismo Beach San Luis Obispo	• Inhabit astatic rain-filled pools • Typically require small, clear-water sandstone-depression pools and grassed swale, earth slump, or basalt-flow depression pools • Critical habitat has been designated.
San Joaquin dune beetle (*Coelus gracilis*)	SC	Avenal	• Fossil dunes at the western edge of San Joaquin Valley. • Sites with sandy substrates.
Morro Bay kangaroo rat (*Dipodomys heermanni morroensis*)	FE/CE	Morro Bay South	• Inhabits a great diversity of habitats • Typically requires sandy valley bottoms, and some are more likely to be found on hilly knolls with shallow soils • Critical habitat has been designated.

[1] Quad - Short for quadrangle. A standard map size and scale used by the U.S. Geological Survey. Typically refers to a map sheet, 7.5 minute or 15 minute (latitude and longitude) series. Refer to Figure 2.5-1 for the quad keymap.

Table 2.5-3

Common Name/ Scientific Name	Status (Federal/ State)	Project Quads[1] Containing Occurrence Records	Habitat Requirements
Giant kangaroo rat (*Dipodomys ingens*)	FE/CE	Chimineas Ranch Lokern McKittrick Summit Reward West Elk Hills	• Scrub desert and piedmont are the basic habitats of giant kangaroo rats • Prefers relatively flat homogenous terrain with shrubs and rocks being almost totally absent • Typical habitat are areas of easily excavated sandy loam covered with annual grasses and herbs
Short-nosed kangaroo rat (*Dipodomys nitratoides brevinasus*)	SC	Belridge Guijarral Hills Lokern Reward West Elk Hills	• Grasslands and arid scrublands, especially those with *Atriplex*, on west side of the San Joaquin Valley. • Friable soils on flat to gently sloping terrain.
Tipton kangaroo rat (*Dipodomys nitratoides nitratoides*)	FE/CE	Buttonwillow Chimineas Ranch Lokern West Elk Hills	• Prefers arid and alkaline plains under shrub and grass vegetation • Soft friable soils away from seasonal flooding. • Often burrows in elevated soils at the bases of shrubs.
Tidewater goby (*Eucyclogobius newberryi*)	FE	Morro Bay North Morro Bay South Oceano Pismo Beach Port San Luis	• Inhabits lagoons formed by streams running into the sea • Brackish and cool water • The tidewater goby prefers salinities of less than 10 ppt (less than a third of the salinity found in the ocean,) and is thus more often found in the upper parts of the lagoons, near their inflow • Revised critical habitat has been proposed.
Western mastiff bat (*Eumops perotis*)	SC	Belridge Buttonwillow Guijarral Hills Lokern San Luis Obispo	• Semi-arid to arid habitats, including grassland, coniferous forest, coastal scrub, chaparral, and others. • Roosts in crevices, buildings, tunnels, and trees, and on cliff faces.
Blunt-nosed leopard lizard (*Gambelia sila*)	FE/CE	Avenal Belridge Branch Mountain Buttonwillow Chimineas Ranch Guijarral Hills Lokern McKittrick Summit Reward West Elk Hills	• Inhabits semiarid grasslands, alkali flats, and washes • Prefers flat areas with open space for running, avoiding densely vegetated areas •
San Joaquin whipsnake (*Masticophis flagellum ruddocki*)	SC	Belridge Chimineas Ranch Garza Peak McKittrick Summit Reward	• Valley grassland and saltbush scrub in San Joaquin Valley. • Open dry, mostly treeless areas. • Uses mammal burrows for shelter and laying eggs.
San Diego desert woodrat (*Neotoma lepida intermedia*)	SC	Morro Bay South Port San Luis	• Coastal scrub habitats in southern and central California. • Uses rock outcrops, rocky cliffs, and patches of cactus.

Table 2.5-3

Common Name/ Scientific Name	Status (Federal/ State)	Project Quads[1] Containing Occurrence Records	Habitat Requirements
Steelhead - south/central California coast DPS (*Oncorhynchus mykiss irideus*)	FT	Arroyo Grande NE Morro Bay North Morro Bay South Oceano Pismo Beach Port San Luis San Luis Obispo	• Populations in the Sacramento and San Joaquin rivers and their tributaries • Critical habitat has been designated.
Tulare grasshopper mouse (*Onychomys torridus tularensis*)	SC	Avenal Belridge Buttonwillow Garza Peak Lokern McKittrick Summit Shandon Simmler West Elk Hills	• Arid scrub habitats • Feeds on arthropods.
San Joaquin pocket mouse (*Perognathus inornatus*)	SC	Belridge Buttonwillow Guijarral Hills Lokern McKittrick Summit Reward Shandon Simmler West Elk Hills	• Usually occurs in grasslands and blue oak woodland. • Needs friable soils.
San Luis Obispo pyrg snail (*Pyrgulopsis taylon*)	--	San Luis Obispo	• Freshwater habitats in San Luis Obispo County.
California red-legged frog *(Rana aurora draytonii)*	FT/SC	Arroyo Grande NE Atascadero Los Mochis Hills Morro Bay North Morro Bay South Nipomo Oceano Pismo Beach San Luis Obispo Tar Springs Ridge Templeton	• Inhabits lowlands and foothills in or near permanent sources of deep water with dense, shrubby or emergent riparian vegetation • Requires 11-20 weeks of permanent water for larval development. Must have access to aestivation habitat • Critical habitat has been designated
Buena Vista Lake shrew (*Sorex ornatus relictus*)	FT	Buttonwillow	• Prefers dense vegetation around the perimeter of marshes, lakes or sloughs • Current distribution is unknown but likely to be very restricted due to the loss of habitat • Critical habitat has been designated.
Western spadefoot toad (*Spea hammondii*)	SC	Chimineas Ranch Cholame Hills Cholame Valley Estrella Guijarral Hills Morro Bay South Templeton	• Grasslands and valley foothill woodlands. • Needs vernal pools for brdding and egg-laying,

Table 2.5-3 Sheet 4 of 4

Common Name/ Scientific Name	Status (Federal/ State)	Project Quads[1] Containing Occurrence Records	Habitat Requirements
American badger (*Taxidea taxus*)	SC	Arroyo Grande NE Avenal Buttonwillow Garza Peak Lokern Reward San Luis Obispo Shandon Simmler Templeton The Dark Hole West Elk Hills	• Found in drier phases of woodland, shrubland, and grassland habitats. • Needs friable, uncultivated soils. • Preys on fossorial small mammals.
Giant garter snake *Thamnophis gigas*	FT/CT	Buttonwillow	• Prefers freshwater marsh and low gradient streams. Has adapted to drainage canals and irrigation ditches • Critical habitat proposed for listing
Le Conte's thrasher (*Toxostoma lecontei*)	SC	Belridge Reward West Elk Hills	• Mostly in dry washes and arid scrub and alkali scrub habitats. • Nests in arid shrubs or cactus, 2 – 3 feet above ground.
San Joaquin kit fox (*Vulpes macrotis mutica)*	FE/CT	Avenal Belridge Buttonwillow Chimineas Ranch Cholame Valley Estrella Guijarral Hills McKittrick Summit Reward Shandon Simmler Templeton West Elk Hills	• Inhabits annual grasslands or grassy open stages with scattered shrubby vegetation • Need loose-textured sandy soils for burrowing, and a suitable prey base • Critical habitat proposed for listing

Federal
FE = Listed as Endangered under the federal Endangered Species Act
FT = Listed as Threatened under the federal Endangered Species Act
State
CE = Listed as endangered under the California Endangered Species Act
CT = Listed as threatened under the California Endangered Species Act
CR = Listed as Rare in California
SC = Species of Concern

TABLE 2.6-1

POPULATION TRENDS OF THE STATE OF CALIFORNIA AND OF SAN LUIS OBISPO AND SANTA BARBARA COUNTIES

Year	State of California	San Luis Obispo County	Santa Barbara County	Notes
1940	6,907,387	33,246	70,555	(a)
1950	10,586,233	51,417	98,220	(a)
1960	15,717,204	81,044	168,962	(a)
1970	19,953,134	105,690	264,324	(a)
1980	23,668,562	155,345	298,660	(a)
1990	29,760,021	217,162	369,608	(a)
2000	33,871,648	246,681	399,347	(a)
2010	39,135,676	269,734	434,497	(b)
2020	44,135,923	293,540	459,498	(b)
2030	49,240,891	316,613	484,570	(b)
2040	54,266,115	338,760	509,920	(b)
2050	59,507,876	364,748	534,447	(b)

Notes: (a) U.S. Census Bureau (Reference 74)
(b) Population Projections by State of California Department of Finance (Reference 73)

TABLE 2.6-2

MINORITY AND LOW INCOME POPULATION INFORMATION

County	Total Block Groups Within 50 Miles	American Indian or Alaskan Native	Asian	Native Hawaiian or Pacific Islander	Black	All Other Single Minorities	Multi-Racial Minorities	Aggregate of Minority Races	Hispanic Ethnicity	Low-Income
Kern	1	0	0	0	0	0	0	1	1	0
Monterey	2	0	0	0	0	0	0	0	0	0
San Luis Obispo	160	0	0	0	0	0	0	8	8	0
Santa Barbara	131	0	0	0	0	0	0	56	43	12
Total	194	0	0	0	0	0	0	65	52	12
State Averages		0.5%	10.8%	0.3%	6.4%	0.2%	2.7%	53%	32.4%	10.6%

TABLE 2.6-3

TRANSIENT POPULATION AT RECREATION AREAS WITHIN 50 MILES OF THE DCPP SITE

Name	Visitor Days	Name	Visitor Days
State Parks [(a)]		Los Padres National Forest [(c)]	
Cayucos State Beach	698,000	Agua Escondido	700
Hearst San Simeon State Historical Monument	795,000	American Canyon	800
Montana de Oro State Park	683,000	Balm of Gilead	200
Morro Bay State Park	1,129,000	Brookshire Springs	1,600
Morro Strand State Beach	129,000	Buckeye	200
Pismo State Beach	1,297,000	Cerro Alto	15,600
San Simeon State Park	696,000	French	200
W. R. Hearst Memorial State Beach	213,000	Frus	700
		Hi Mountain	4,800
County and Local Parks [(b)]		Horseshoe Springs	1,400
Lake Nacimiento	345,000	Indians	600
San Antonio Reservoir	361,000	Kerry Canyon	300
Avila Beach	800,000	La Panza	4,400
Cambria	15,000	Lazy Camp	500
Cayucos Beach	918,000	Miranda Pine	2,300
Cuesta	67,000	Navajo	2,800
Lopez Recreation Area	379,000	Pine Flat	300
Nipomo	168,000	Pine Springs	400
Oceano	95,000	Plowshare Springs	300
San Miguel	54,000	Queen Bee	2,200
Santa Margarita Lake	169,000	Stony Creek	1,100
Shamel	130,000	Sulphur Pot	1,000
Templeton	99,000	Upper Lopez	600
Los Alamos Park	45,000	Wagon Flat	2,200
Miguelito Park	36,000		
Ocean Park	105,000		
Rancho Guadalupe Dunes Park	48,000		
Waller	450,000		
Atascadero Lake	300,000		

(a) California Department of Parks and Recreation (July 1998 through June 1999).
(b) County Park Departments.
Monterey and Santa Barbara Counties (July 1999 through June 2000).
San Luis Obispo County (July 1998 through June 1999).
(c) Los Padres National Forest (July 1971 through June 1972). Current data is no longer compiled).

TABLE 2.7-1

PROPERTY TAX BREAKDOWN FOR 2004-2008

Year	SLO County Property Tax Revenues (Millions)	Property Tax paid by DCPP (Millions)	Percent of SLO County Property Tax Revenues
2008-2009	425	22.3	5.6%
2007-2008	404	20.7	5.6%
2006-2007	371	20.1	5.8%
2005-2006	334	21.4	6.3%
2004-2005	301	20.4	6.6%

Source: References 78, 79, 80, 81, 82, and 83

TABLE 2.8-1

HOUSING STATISTICS FOR SAN LUIS OBISPO AND SANTA BARBARA COUNTIES

	1990	2000	Percent Change
San Luis Obispo County			
Total Housing Units	90,200	102,275	11.8
Occupied Units	80,281	92,739	13.4
Vacant Units	9,919	9,536	-3.9
Median House Value ($)	213,200	230,000	7.3
Santa Barbara County			
Total Housing Units	138,149	142,901	3.3
Occupied Units	129,802	136,622	5.0
Vacant Units	8,347	6,279	-24.8
Median House Value ($)	249,200	293,000	14.9

Source: References 89 and 90

TABLE 2.9-1

MAJOR SAN LUIS OBISPO COUNTY WATER SUPPLIERS[a]

Water Supplier[a]	Water Source[a]	Average Daily Use (MGD) [b]	Maximum Daily Capacity (MGD) [b]
Arroyo Grande Water Department	Purchased SW	3.2	7.0
Atascadero Mutual Water Co.	GW	5.5	17.4
California Men's Colony	SW	1.2	3.0
Cambria Community Services District	GW	0.9	1.7
Golden State Water Company – Los Osos	GW	0.9	3.49
Golden State Water Company – Nipomo	GW	2.43	2.7
Grover Beach Water Department	Purchased SW	No records available [c]	No records available [c]
Los Osos Community Services District	GW	0.84	2.53
Morro Bay Water Department	Purchased SW	1.3	3.25
Nipomo Community Services District	GW	3.45	5.6
Oceano Community Services District	Purchased SW	2.8	5.6
Paso Robles Water Department	GW	7.2	12.3
Pismo Beach Water Department	Purchased SW	1.92	3.26
San Luis Obispo Water Department	SW	6.0	~20.0
Templeton Community Services District	GW	2.5	2.7

GW = Groundwater
SW = Surface water
MGD = Million Gallons Daily
a. Reference 92; active water systems serving a population >3,301.
b. Data obtained from individual water suppliers in 10/2008 (Reference 94).
c. The Grover Beach Water Department does not keep records providing this data.

TABLE 2.9-2

CURRENT AND FUTURE – ROADWAYS LOS CLASSIFICATIONS

Road/Route (Class)	Current			Future		
	ADT	LOS*	Peak Hr	ADT	LOS	Peak Hr
Avila Beach Drive (Collector – 2 Lanes)**	10,157	D	1,396	12,359	F	1,699
San Luis Bay Drive (Collector – 2 Lanes)	6,532	A	625	7,948	A	761
Shell Beach Road (Collector – 2 Lanes)	4,945	A	429	6,017	A	522
Los Osos Valley Road (Arterial – 2 Lanes)	16,568	D	1,673	20,160	F	2,036
Diablo Canyon Road (Collector – 2 Lanes)	-	A	-	-	A	-
Pecho Valley Road (Collector – 2 Lanes)	1,512	A	178	1,840	A	217
Traffic on Highway 101 at specified exits (Major – 4 Lanes)						
SLO County Jct. Rte. 166 East	62,000	D	6,400	79,542	F	7,788
Teftt St.	51,000	C	4,500	54,145	C	5,476
Los Berros Rd.	51,000	C	4,700	54,145	C	5,719
Arroyo Grande, Bridge St.	51,000	C	6,000	54,145	C	7,301
Arroyo Grande, Jct. Rte. 227 North, Grand Ave.	45,000	B	5,500	47,067	B	6,692
Arroyo Grande, Brisco Rd.	46,000	B	5,700	48,065	B	6,936
Pismo Beach, Oak Park Rd.	51,000	C	6,400	53,056	C	7,788
Pismo Beach, Pismo Oaks	58,000	C	7,400	60,047	D	9,004
Pismo Beach, So. Pismo Beach (Villa Creek)	66,000	D	8,400	70,201	E	10,221
Pismo Beach, Jct. Rte. 1 South	55,000	C	8,400	66,925	D	10,221
North Shell Beach	55,000	C	4,750	66,925	D	5,780
Avila Rd.	62,000	D	7,800	73,660	E	9,491
North Avila Rd./San Luis Bay Dr.	58,000	C	6,900	75,861	F	8,396
Santa Fe	69,000	E	8,300	89,189	F	10,100
San Luis Obispo, Los Osos Rd.	69,000	E	8,000	103,881	F	9,735
San Luis Obispo, Madonna Rd.	54,000	C	5,500	72,240	E	6,692
San Luis Obispo, Jct. Rte. 227 So., Marsh St.	75,000	F	8,600	101,287	F	10,465
San Luis Obispo, Jct. Rte. 1 North, Osos St.	71,000	E	8,000	97,766	F	9,735
San Luis Obispo, California Blvd.	62,000	D	7,000	86,343	F	8,518
San Luis Obispo, Grand Ave.	54,000	C	6,000	77,695	F	7,301
San Luis Obispo, Buena Vista	41,000	B	4,600	57,275	C	5,597
San Luis Obispo North City Limits	48,500	B	5,300	62,299	D	6,449
Jct. Rte. 58 East, Santa Margarita Creek	40,500	B	4,300	51,731	C	5,232
Atascadero, Santa Barbara Rd.	38,500	B	4,150	49,881	C	5,050
Atascadero, Santa Rosa, Rd.	40,500	B	4,450	51,731	C	5,415
Atascadero, Curbaril Ave.	41,500	B	4,650	54,252	C	5,658
Atascadero, Jct. Rte. 41	41,500	B	4,550	54,252	C	5,537
Atascadero, Traffic Way	44,500	B	4,900	55,480	C	5,962
Atascadero, San Anselmo Rd.	47,000	B	5,100	62,562	D	6,206
Atascadero, Del Rio Rd.	42,000	B	4,500	46,350	B	5,476
San Ramon Rd.	42,000	B	4,450	46,350	B	5,415
Templeton, Vineyard Dr.	44,000	B	4,550	50,811	C	5,537

TABLE 2.9-2

Road/Route (Class)	**Current**			**Future**		
	ADT	**LOS***	**Peak Hr**	**ADT**	**LOS**	**Peak Hr**
Templeton, Los Tablas Ave.	42,000	B	3,900	51,632	C	4,746
Templeton, Main St.	42,000	B	3,900	51,632	C	4,746
Jct. Rte. 46 West	44,500	B	3,750	57,015	C	4,563
South Paso Robles	49,500	B	5,800	63,227	D	7,058
Paso Robles, 13th St.	33,500	B	3,950	42,104	B	4,806
Paso Robles, Jct. Rte. 46 East	29,000	A	3,450	36,358	B	4,198
Paso Robles, North Paso Robles	21,500	A	2,150	31,389	B	2,616

Notes: *LOS calculated using Santa Barbara County thresholds or Highway Capacity Software. ADT=Average Daily Traffic, LOS=Level of Service, Peak Hr=Peak hour
** LOS for Avila Beach Drive based on peak hour numbers.
Percent growth based on 1.8% annual population growth predicted for the state of California, which is comparable to San Luis Obispo's 1.4% growth rate between 1990 and 2000 (Reference 93).
Growth numbers based on data available from CalTrans over past 5 years. Ten year growth numbers are not available.
Sources: Highway 101=CalTrans, 2001; Avila Beach Roads=San Luis Obispo Traffic Volumes, 2002, which included data from as far back as 1993.

TABLE 2.9-3

SAN LUIS OBISPO COUNTY SCHOOL DISTRICT STATISTICS

School Districts	City	Number of Schools	Number of Students	Student to Teacher Ratio
Atascadero Unified	Atascadero	12	5,030	20.6
Cayucos Elementary	Cayucos	1	212	17.1
Coast Unified	Cambria	5	862	16.8
Lucia Mar Unified	Arroyo Grande	17	10,866	20.9
PasoRobles Joint Unified	Paso Robles	12	6,835	20.5
Pleasant ValleyJoint Union Elementary	San Miguel	1	137	17.1
San Luis Coastal Unified	San Luis Obispo	16	7,241	19
San Luis Obispo Co. CYA District	Paso Robles	1	204	8.7
San Luis Obispo Co. Off. of Education	San Luis Obispo	4	765	12.6
San Miguel Joint Union Elementary	San Miguel	2	454	17.7
Santa Lucia ROP	Arroyo Grande	1	N/A	N/A
Shandon Joint Unified	Shandon	4	384	14.2
Templeton Unified	Templeton	7	2,563	21.1

N/A = Information not available.
Source: Reference 95

TABLE 2.10-1

ATTAINMENT STATUS OF SLO COUNTY, ALL MONITORING STATIONS

Air Basin	O_3		CO		NO_2		SO_2		$PM_{2.5}$		PM_{10}	
	State	*Fed*	*State*	*Fed*	*State*	*Fed*	*State*	*Fed*	*State*	*Fed*	*State*	*Fed*
SLO County	N	U/A	A	U/A	A	U/A	A	U	A	U/A	A	U

Notes: A=Attainment of Standards; N=Non-Attainment; U=Unclassified; U/A=Unclassified/Attainment

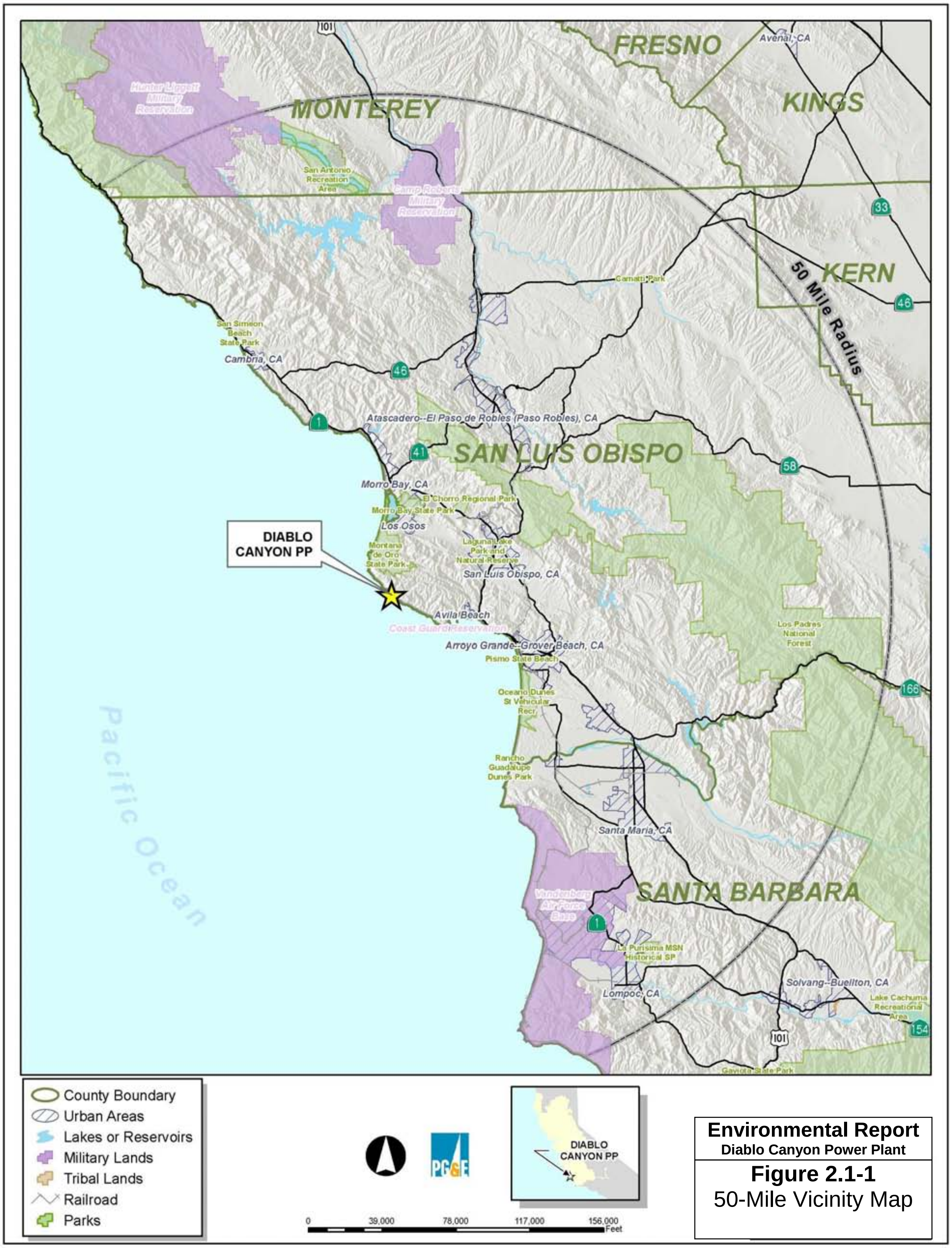
Source: Reference 96, Last updated February 2, 2009.

TABLE 2.11-1

SITES LISTED IN THE NATIONAL REGISTER OF HISTORIC PLACES THAT FALL WITHIN A 6-MILE RADIUS OF DCPP OR WITHIN A 1.2-MILE RADIUS OF TRANSMISSION LINES

Site Name	**Location**
Rancho Cañada de Los Osos y Pecho y Islay, including CA-SLO-2	Listed as Restricted Address, San Luis Obispo, but located on PG&E property
Carrizo Plain Rock Art Discontiguous District	Restricted Address, California Valley
Corral de Piedra	South of San Luis Obispo on Price Canyon Rd, San Luis Obispo

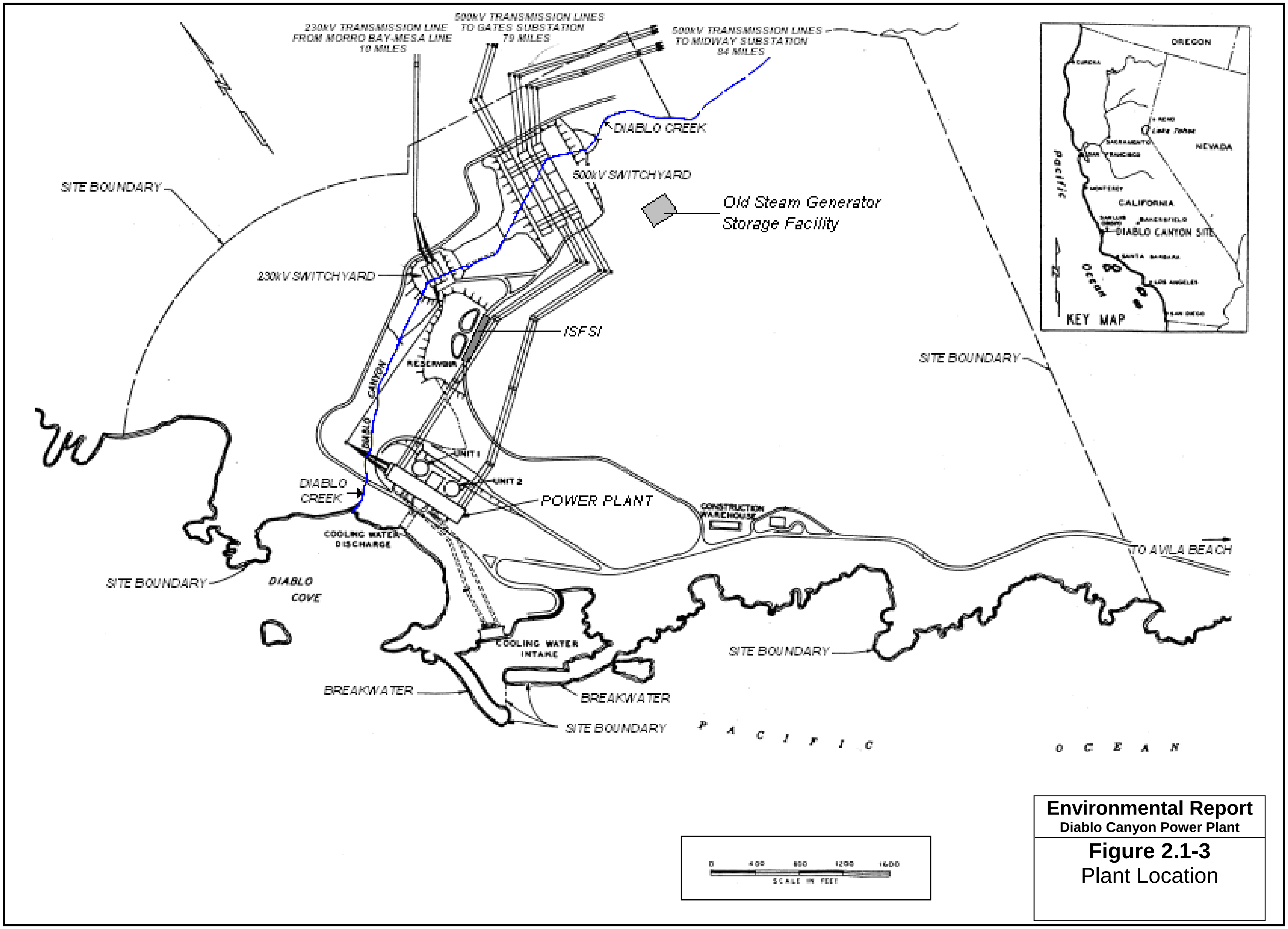
Source: Reference 125



Environmental Report
Diablo Canyon Power Plant

Figure 2.1-1
50-Mile Vicinity Map

Environmental Report
Diablo Canyon Power Plant
Figure 2.1-2
6-Mile Vicinity Map



Environmental Report
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Figure 2.1-3
Plant Location

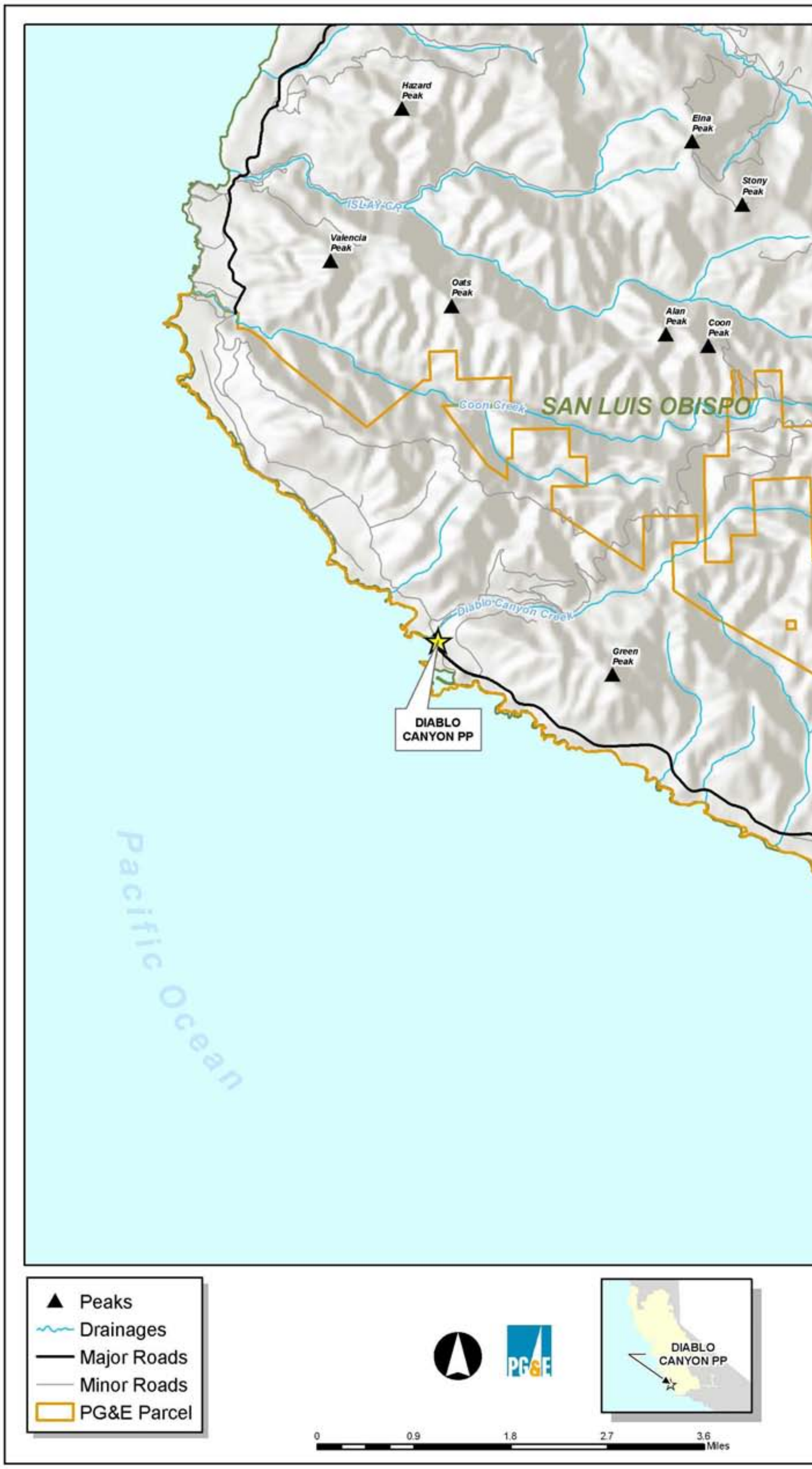

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Figure 2.2-1
Streams in Vicinity of PG&E Property

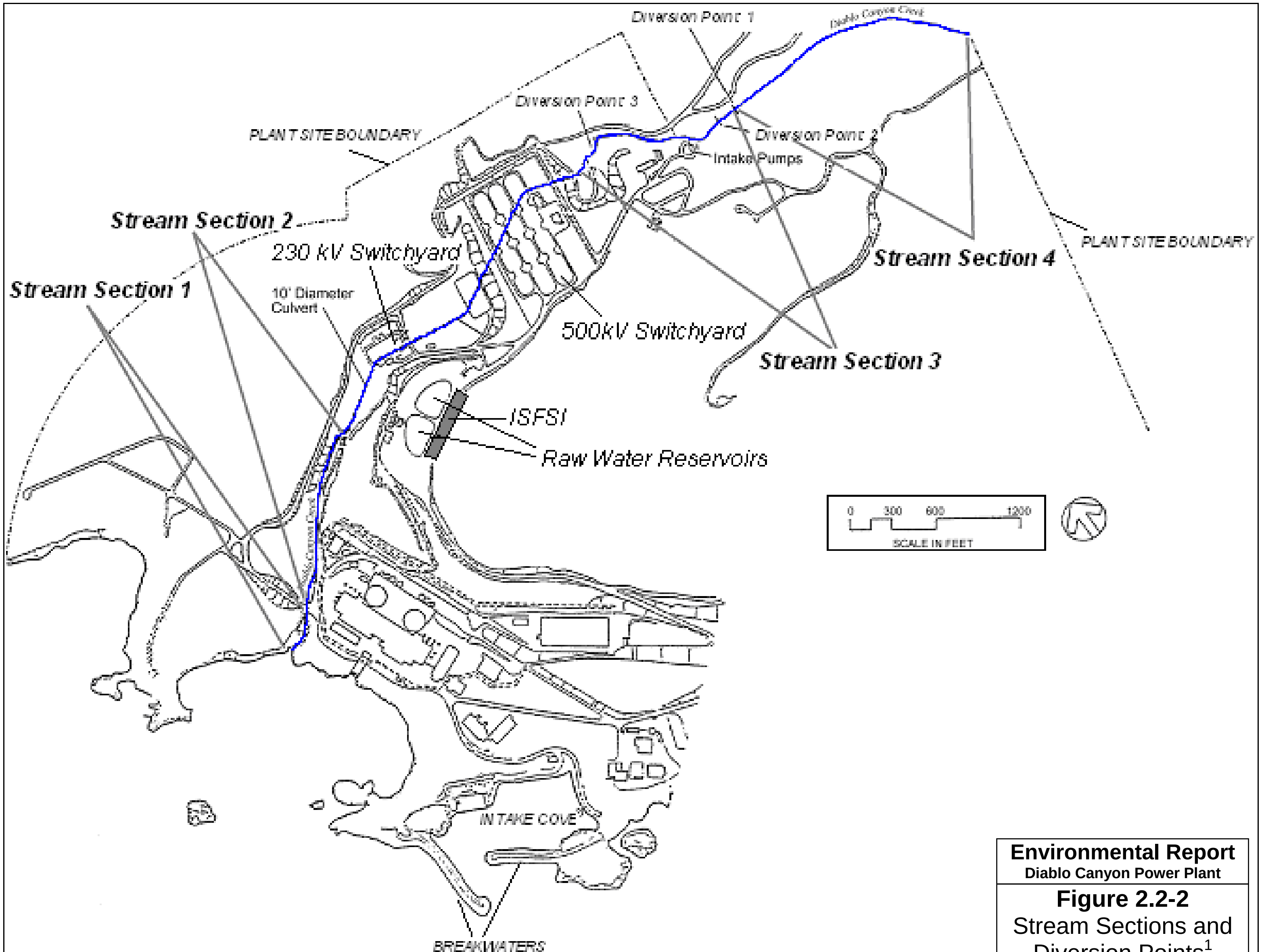

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Figure 2.2-2
Stream Sections and Diversion Points[1]

[1] Diversion Points 1, 2, and 3 were abandoned in 2008. Associated conveyance piping and pumps were removed.

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Diablo Canyon Power Plant

Figure 2.3-1
Onsite Monitoring Well Locations

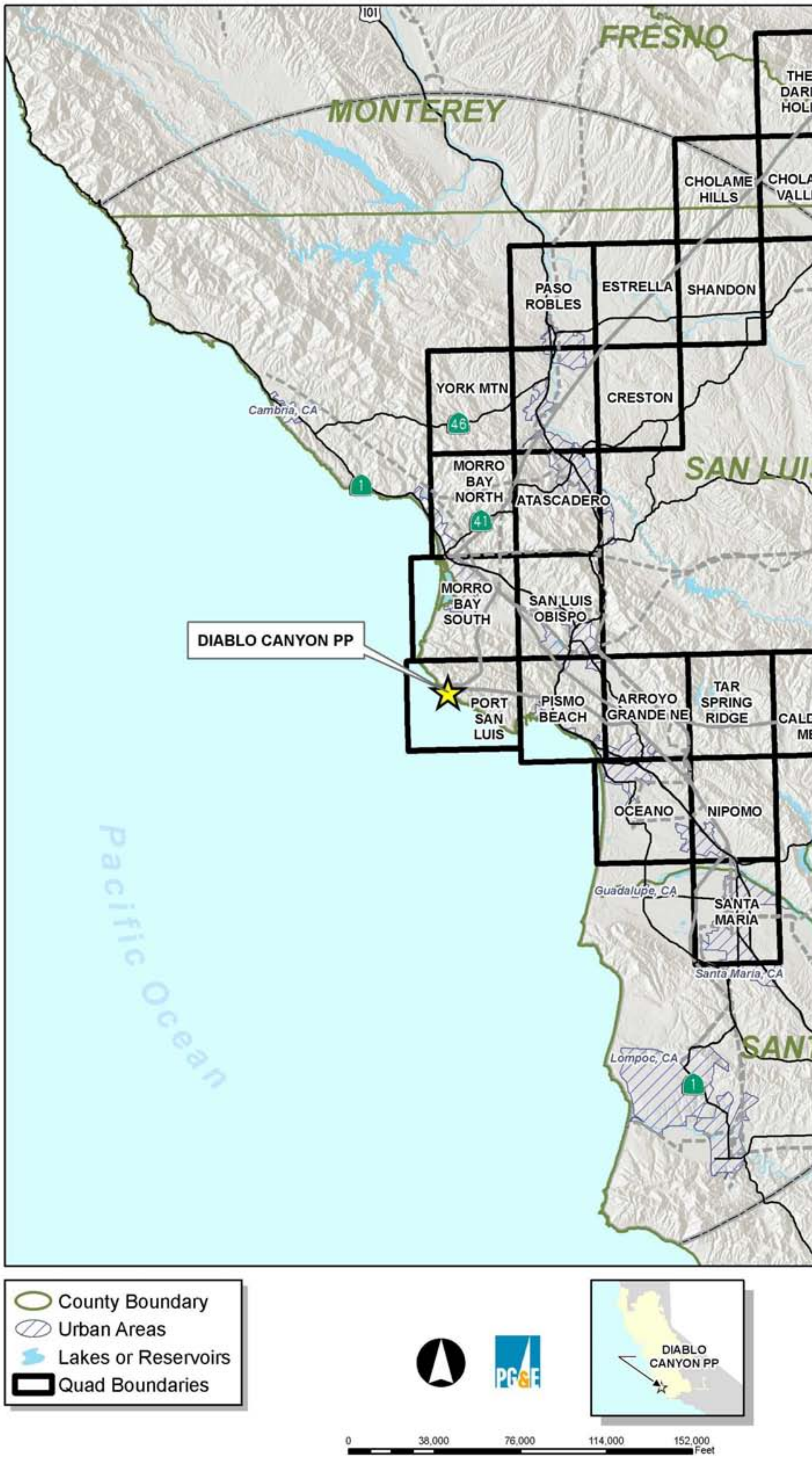

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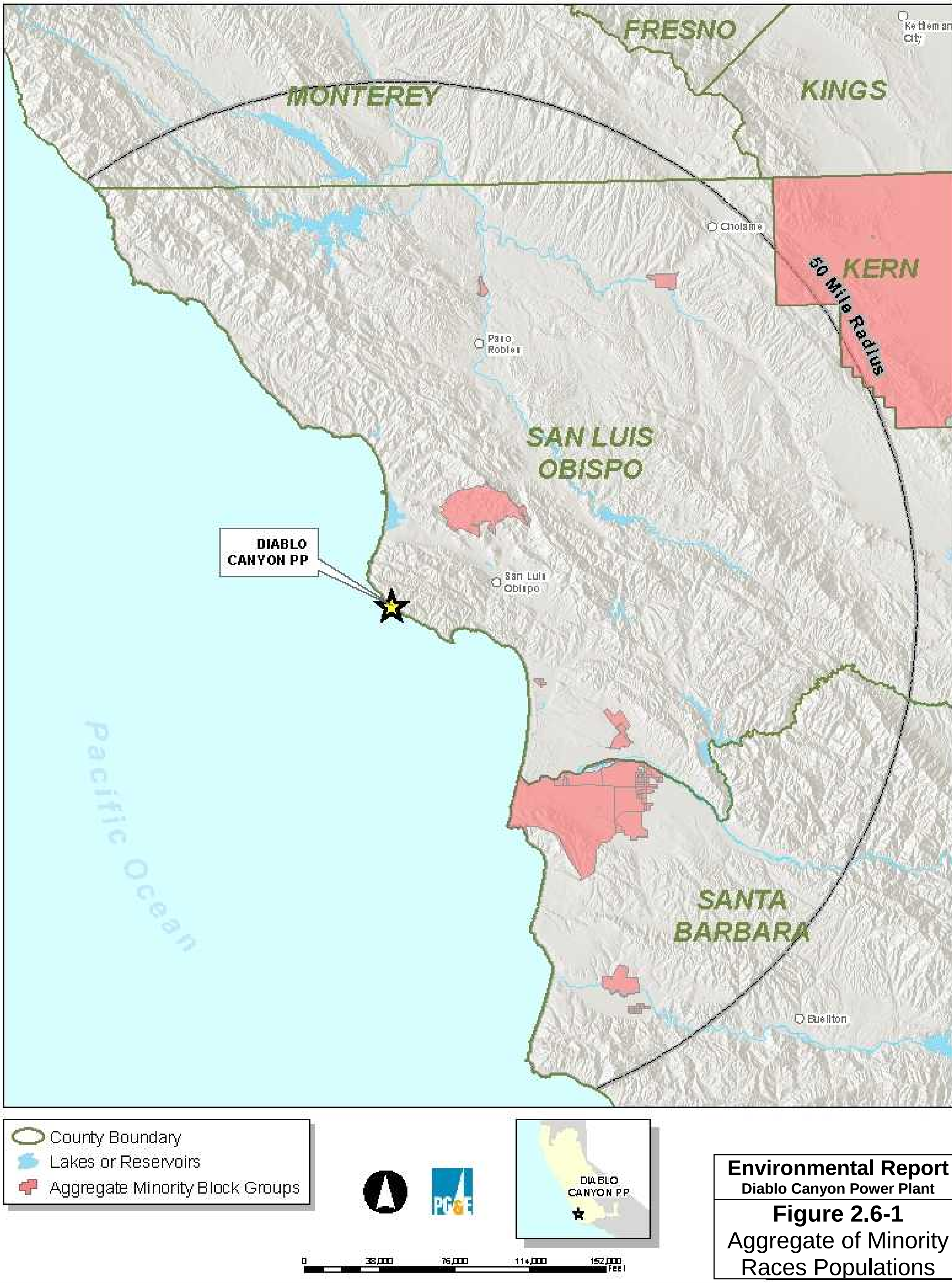
Figure 2.5-1
Transmission Line Corridor Project Quads



Environmental Report
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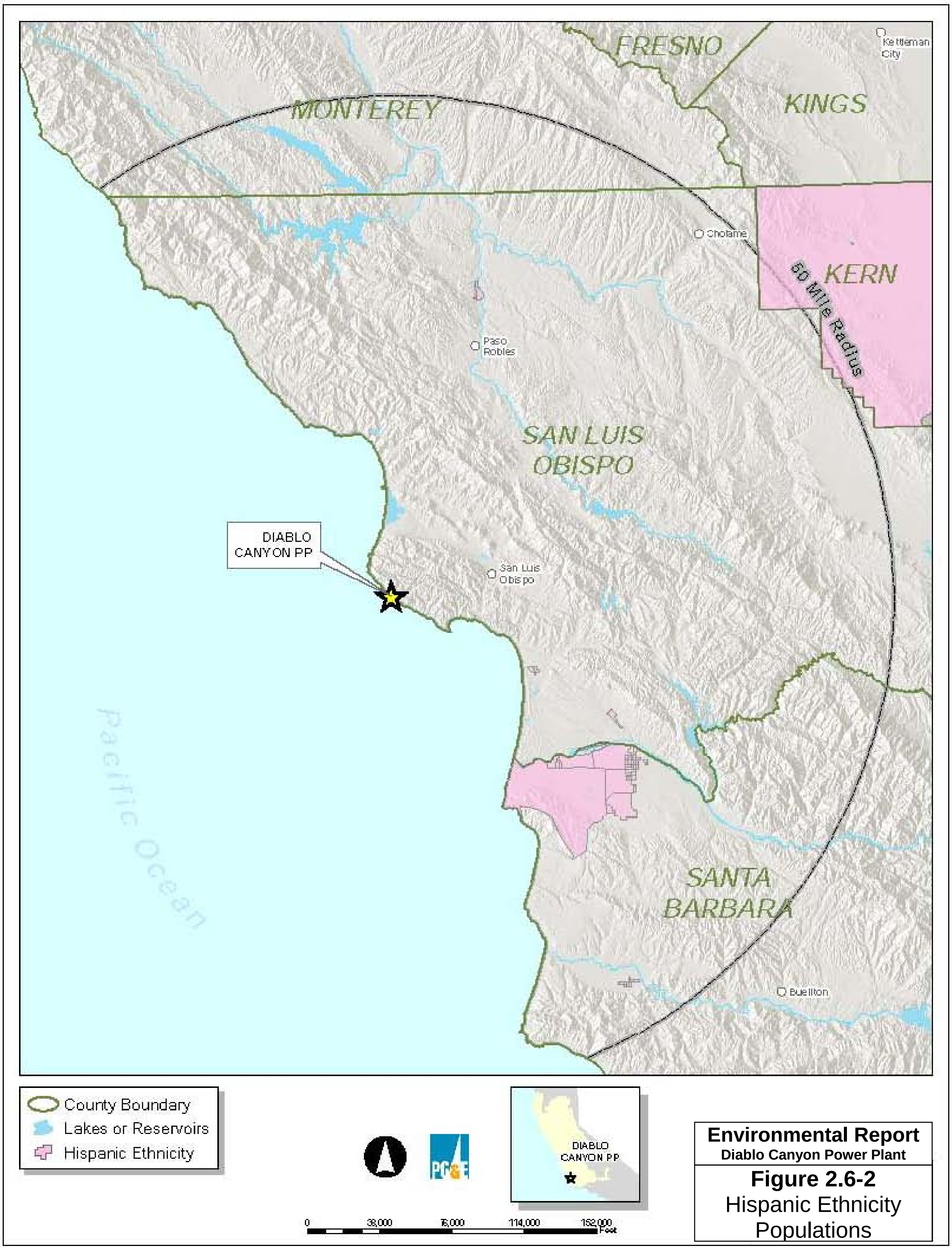
Figure 2.6-1
Aggregate of Minority Races Populations



Environmental Report
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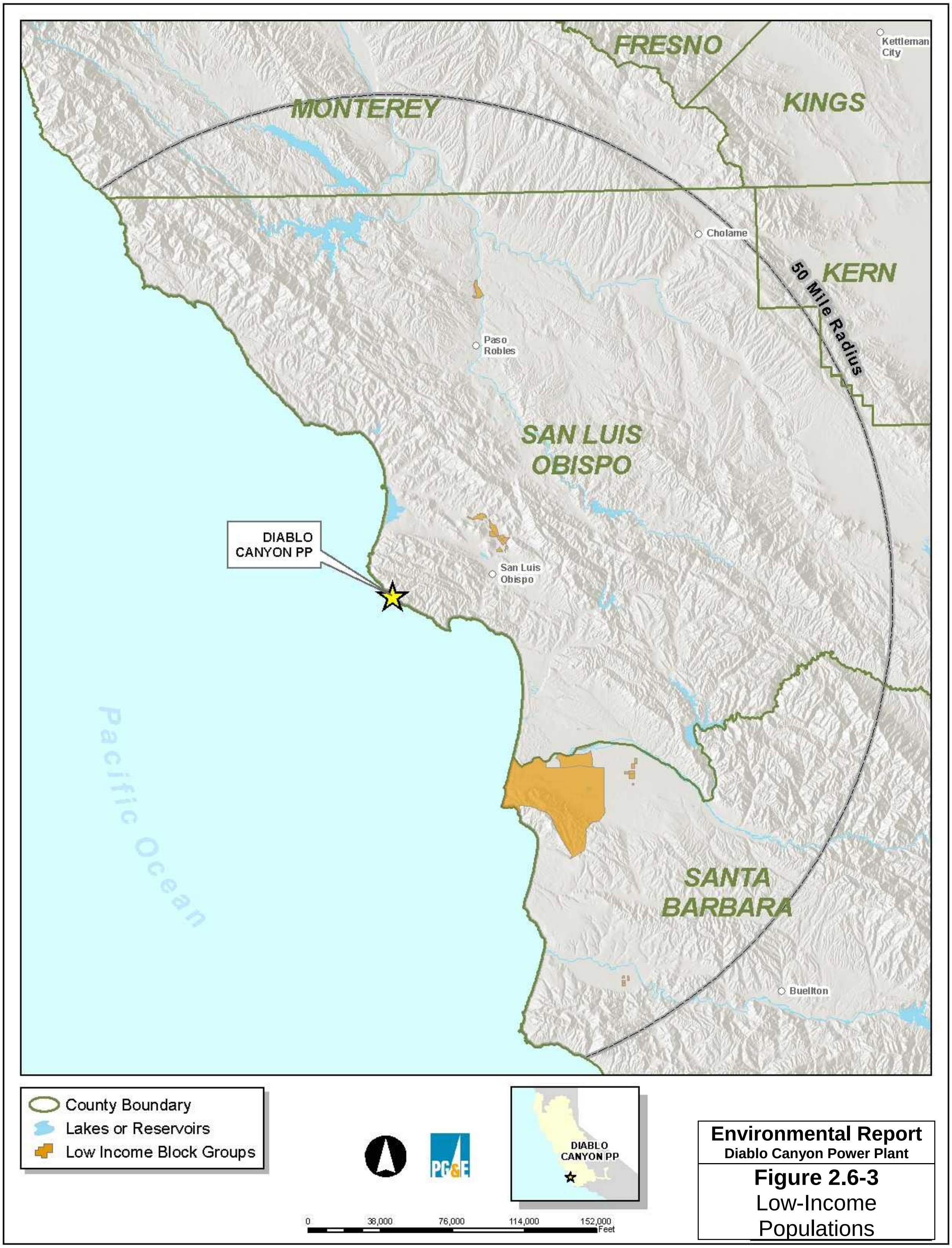
Figure 2.6-2
Hispanic Ethnicity Populations



Environmental Report
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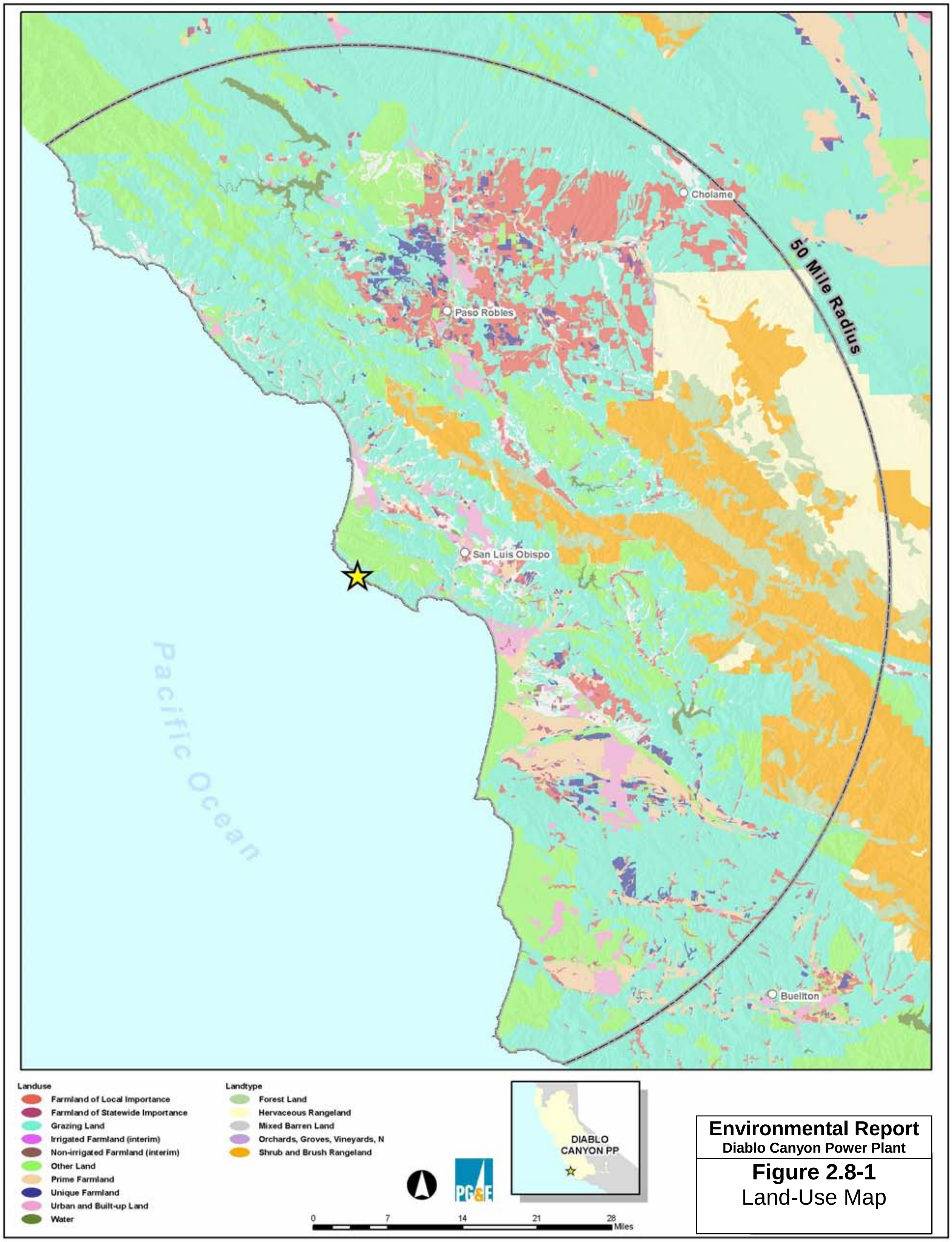
Figure 2.6-3
Low-Income Populations



Environmental Report
Diablo Canyon Power Plant

Figure 2.8-1
Land-Use Map

Environmental Report
Diablo Canyon Power Plant

Figure 2.9-1
DCPP Transportation Map

CHAPTER 3 – THE PROPOSED ACTION

NRC

"… The report must contain a description of the proposed action, including the applicant's plans to modify the facility or its administrative control procedures…" 10 CFR 51.53(c)(2)

Pacific Gas and Electric (PG&E) proposes that the U.S. Nuclear Regulatory Commission (NRC) renew the operating licenses for Diablo Canyon Power Plant (DCPP) for an additional 20 years. Renewal would give PG&E and the state of California the option of relying on DCPP to meet future electricity needs. Section 3.1 discusses the plant in general. Sections 3.2 through 3.4 address potential changes that could occur as a result of license renewal.

3.1 GENERAL PLANT INFORMATION

DCPP is a nuclear-powered steam electric generating facility that began commercial operation on May 7, 1985 for Unit 1 and March 13, 1986 for Unit 2. Each unit is powered by a Westinghouse pressurized water reactor (PWR). Unit 1 produces a reactor core power of 3,411 megawatts-thermal; Unit 2 produces 3,411 megawatts-thermal. The design net electrical capacities are 1,138 and 1,147 megawatts-electric for Units 1 and 2, respectively. Figure 3.1-1 depicts the site layout.

The following subsections provide information on the reactor and containment systems, the cooling and auxiliary water systems, and the electric transmission system. Additional information about DCPP is available in the following documents:

- Final Environmental Statement (FES) for operation of the plant (Reference 2),
- Generic Environmental Impact Statement for License Renewal of Nuclear Plants (Reference 3), and
- DCPP's Final Safety Analysis Report Update (Reference 1).

3.1.1 REACTOR AND CONTAINMENT SYSTEMS

The nuclear steam supply system at DCPP is a four-loop Westinghouse pressurized water reactor. The reactor core heats up to approximately 581°F. Because the pressure exceeds 2,000 psi, the water does not boil. The heated water is pumped to four U-tube heat exchangers known as steam generators where the heat boils the water on the shell-side into steam. After drying, the steam is routed into the turbines. The steam yields its energy to turn the turbines, which are connected to the electrical generator. Both Unit 1 and Unit 2 steam generators were replaced in 2008 and 2009 by new Westinghouse steam generators (Reference 4). The nuclear fuel is low-enriched uranium dioxide with enrichments 5 percent by weight uranium-235 or less and fuel burnup levels of a batch average of approximately 49,000 megawatt-days per metric ton of uranium (MWD/MTU), and less than a maximum of 62,000 MWD/MTU.

The reactor, steam generators, and related systems are enclosed in a containment building that is designed to prevent leakage of radioactivity to the environment in the improbable event of a rupture of the reactor coolant piping. The containment building is a reinforced concrete cylinder with a slab base and hemispherical dome. A welded steel liner is attached to the inside face of the concrete shell to ensure a high degree of leak tightness. In addition, the 3.6 ft thick concrete walls serve as a radiation shield for both normal and accident conditions.

The containment building is ventilated to maintain pressure and temperatures within acceptable limits. The containment ventilation system can also purge the containment prior to entry. Exhaust from the ventilation system is monitored for radioactivity before being released to the plant vent. High efficiency particulate air (HEPA) filters can be used when needed to filter the air before releasing it. The containment building can be isolated if needed.

3.1.2 COOLING AND AUXILIARY WATER SYSTEMS

The water systems most pertinent to license renewal are those that draw from surface water bodies and groundwater. At DCPP, the once-through cooling (OTC) Circulating Water System draws from and discharges to the Pacific Ocean. The system removes the heat rejected from the main condensers.

A seawater reverse osmosis treatment unit provides the majority of freshwater for plant primary and secondary systems makeup, fire protection system source water, and plant domestic water system supply. The unit is supplied with raw seawater drawn from the power plant OTC system intake, and has the capacity to produce 450 gpm of freshwater. Groundwater from an onsite deep well is also available to supplement freshwater supply as necessary. Supplement of reverse osmosis system supply by the deep well is generally only required during equipment maintenance periods, or during plant start-up following refueling or forced outage when freshwater consumption is significantly increased.

3.1.2.1 Surface Water

Condenser circulating water is seawater from the Pacific Ocean. The ocean water level normally varies between zero and +6 ft mean lower low water (MLLW) datum. Mean sea level (MSL) zero is equivalent to +2.6 ft MLLW.

A curtain wall at the front of the intake structure limits the amount of floating debris entering the intake structure. Bar racks near the front of the intake structure intercept large submerged debris. The bar racks have 3/8 inch thick bars at 3-3/8 inch centers.

Traveling screens intercept all material larger than the screen mesh opening (3/8 inch clear square openings).

The total flow in each Unit's circulating water system is nominally 867,000 gpm, which is pumped by two circulating water pumps with motors cooled by an air-to-water heat exchanger. The cooling water is provided from the fire water system via a small demineralizer. Each pump has a discharge isolation valve and bypass line around the valve. Approximately 4,000 gpm of the circulating water flow is used per Unit to cool the service water heat exchangers and 1,000 gpm to cool the pump motor cooling water.

Once Through Cooling System

DCPP utilizes an OTC water system whereby seawater is drawn from the Pacific Ocean through a shoreline intake structure, and discharged back to the Pacific Ocean at a second, separate, shoreline location. Ambient temperature seawater is pumped through heat exchanging steam condensers located in the turbine building. Figure 3.1-2 provides a diagram of the OTC system (not to scale). Each Unit utilizes an independent cooling system, however the systems share common intake and discharge structures.

The two main steam condensers for each Unit are in-line directly under the low pressure turbine exhaust. Each condenser consists of two halves with each half independently supplied by one of the 2 intake conduits. Each Unit has two intake seawater conduits that split under the turbine building, and supply one half of each condenser. This configuration provides four distinct condenser quadrants per Unit, with each seawater conduit supplying cooling flow to the inlet of two condenser quadrants.

Individual condenser quadrants contain 58,126 1-inch diameter 41-ft horizontal titanium tubes that provide a large surface area for efficient heat transfer between secondary side turbine steam exhaust and the seawater cooling flow. Following transfer of waste heat, the warmed seawater is discharged back into the ocean through the shoreline outfall located at Diablo Cove. Condensed water on the secondary side is re-circulated to the stream generators and flashed back to turbine steam.

Seawater Intake System

For each Unit, two main seawater circulating water pumps (CWP) provide cooling flow to the main condenser inlets. Each CWP discharges into a concrete conduit approximately 1,800 ft in length that rises from the shoreline intake structure to the turbine building. The conduits measure 11.75-ft square with exception of an initial tapered section leading directly from the pump discharge, and a circular section used for flow monitoring. The CWPs produce a combined rated flow for Unit 1 between 778,000 gpm and 854,000 gpm, and for Unit 2 between 811,000 gpm and 895,000 gpm. Two-Unit combined flow is between 1,589,000 gpm minimum and 1,749,000 gpm maximum during normal plant operations.

Each Unit also has two auxiliary saltwater system (ASW) pumps that supply cooling flow to the safety related component cooling water (CCW) heat exchangers. Each ASW pump is rated at 11,500 gpm. During routine plant operations, only one ASW train is in use for each Unit, with the second pump in standby mode. Two operating pumps contribute an additional OTC flow of 23,000 gpm. Using maximum pump ratings, total OTC flow during routine full power operations is 1,772,000 gpm, equivalent to 2.55 billion gallons of seawater circulated per day.

Seawater transit time through the power plant is approximately 5 minutes. At full power, cooling flow temperatures are elevated approximately 20°F during condenser pass-through. Average aggregate power plant discharge temperature is 19.6°F above ambient intake seawater temperatures (ΔT). Temperature elevation can vary in response to ocean ambient temperatures, Unit power levels, plant transients, and planned Unit curtailments which may be accompanied by seawater circulator clearance. During the initial license period, OTC system discharge ΔT has been limited by permit to 22°F above intake ambient temperature.

The shoreline intake structure for Units 1 and Unit 2 house the CWPs, vertical debris bar racks, vertical traveling water screen mechanisms (3/8 inch mesh screens), and associated screen rotation and washing equipment. Figure 3.1-3 provides a scaled diagram of the Unit 1 main and auxiliary circulator pump bays, and layout of the debris control and screen wash equipment. Each main circulator draws from an isolated pump bay. Each pump bay is open to the ocean through 3 individually gated 11-ft wide rectangular passages leading through 10-ft wide (nominal) perpendicular vertical traveling screens. Each screening mechanism provides approximately 300 square feet (sq-ft) of filtration area at mean sea level for a total of approximately 900 sq-ft for each CWP. The isolation gates for an individual pump bay can be closed and sealed, and the bay dewatered for maintenance or inspection activities independent of the other bays.

The two ASW pumps for each Unit are serviced by a single 6-ft wide rectangular concrete passage leading through 5-ft wide (nominal) perpendicular vertical traveling screens. The screening mechanism for the auxiliary pump bays provides approximately 150 sq-ft of filtration surface at mean sea level. Leading from the common debris screened inlet passage; the bay then widens and is partitioned into two sides, one for each ASW pump suction inlet.

Unit 1 and Unit 2 intake configuration is mirrored, with the auxiliary pumps and associated bays located near the center of the intake structure. The structure is flat-faced, with all bar racks, dewatering gates, and traveling screen systems installed parallel to the shoreline, and perpendicular to the inlet flow. Total equipment inventory includes 4 CWPs and associated inlet bays, 4 ASW pumps and 2 associated partitioned inlet bays, 14 individual vertical traveling screen wash systems, and 14 bar rack Units installed in front of each traveling screen inlet passage. Figure 3.1-4 provides a scaled cross sectional view of an inlet passage. An additional 9-ft wide bar rack bay serving as a fish escape route is provided at each end of the intake structure bringing the total number of bar rack units to 16. A central concrete partition supporting a screen wash debris collection sump splits the submerged face of the intake into distinct Unit 1 and Unit 2 openings to the ocean environment. The partition is open between the Units behind the bar racks. The opening provides for free flow of seawater and a migration route for fish from one end of the structure to the other.

Cooling System Debris Intrusion Control
During routine operations, the traveling water screens are rotated and washed by high pressure saltwater spray for 15 minutes every 4 hours. In high energy ocean swell events, and/or periods of increased source water debris loading conditions, the traveling screens can be placed into continuous operation at either low or high speed.

The traveling screen wash system spray nozzles discharge into sluiceways located on the intake structures exterior upper deck. The sluiceways flow to a central refuse collection sump. The sump is dewatered by pumping systems capable of transferring high percentage solids laden flow. The saltwater screen wash effluent and entrained debris is pumped from the sump to a discharge outside of the power plant intake cove. Grinding and mincing equipment installed in the inlets of the refuse sump process debris captured by the traveling screens and subsequently washed off. The debris grinders reduce potential for clogging of the sump when seawater inlet flow is laden with significant quantities of ocean debris (primarily kelp and under story algae). Entrained debris smaller than the 3/8-inch screening mesh passes through the cooling system.

Cooling System Heat Treatment
The main condenser OTC system was initially designed for heat treatment to control marine fouling organisms. Heat treatments, effective for management of biofouling primarily caused by mussels, was implemented but discontinued early during the initial license period. Heat treatments were found to be ineffective at managing acorn barnacles (*Megabalanus tintinnabulum*), the primary seawater systems fouling problem. Heat treatment of seawater systems will not be used in the license renewal period.

Discharge and Thermal Effluent
Heated discharge from the main condensers of each Unit combine and flow to a common structure terminating in a shoreline outfall. The discharge for Unit 1 and Unit 2 are parallel within the structure separated by a central concrete partition. Cutouts exist in the dividing wall to promote mixing of thermal effluent between the operating Units. The mixing also provides dilution and reduction of residual oxidants from seawater inlet systems chemical treatments. Figure 3.1-5 provides a side view of the discharge structure and associated cascading weir system.

Discharge flows by gravity from the elevated turbine building into the outfall structure. Within the structure, flow passes over three weirs and across horizontal platforms fitted with vertical impact blocks. The cascading effect of the design creates mixing of the thermal effluent as well as dissipation of hydraulic energy. Width of the discharge flow out the mouth of the structure is 27.5 ft per Unit. Once discharged, the thermal effluent mixes with the receiving water and dissipates across the ocean surface.

Cooling System Biofouling and Chemical Control
The seawater conduits are susceptible to colonization by entrained marine organisms. During the initial operating license period, concrete conduit surfaces in both the intake and discharge systems have been susceptible to extensive fouling with acorn barnacles (*Megabalanus tintinnabulum*), gooseneck barnacles (*Polycipes polymerus*), and to a lesser extent mussels (*Mytilus edulis*). Other marine species also find habitat among the protective substrate created by the primary hard-shelled fouling organisms.

Heavy colonization and growth in the condenser inlet conduits can result in sloughing of fouling material. Individual acorn barnacles or clusters of smaller barnacles, with hard durable calcareous shells larger than 1 inch in diameter, can impinge on main condenser tube sheets and block flow. Sloughed fouling material accumulates on inlet tube sheets resulting in increased backpressure on the intake main circulating water pumps, and reduction of condenser performance. Significant fouling requires manual removal of growth during refueling outages. Mid-cycle Unit curtailments are also often necessary to conduct conduit cleanings and/or perform main condenser inlet debris removal when fouling slough and subsequent tube sheet occlusion become significant.

The chlorination system provides chemical treatment of the circulating water to control the macro and micro fouling in the intake tunnels, piping, and the condenser tubes. The system is used as needed. Liquid sodium hypochlorite and a supplemental chemical, sodium bromide, are stored in tanks at the intake structure (common to both Units). Adequate valving is provided for isolating any of the tanks from the system. Each tank is within a secondary containment tank sized to contain the entire contents of the storage tank. When chlorination is required (based on a time schedule), the chemicals are injected via metering pumps and injected into the intake structure.

Chemical treatment to inhibit initial colonization of seawater conduit surfaces, as well as retard growth rates of established fouling, will continue to be used during the period of extended operation. Biofouling inhibition coatings are also used within the seawater systems, however, such coatings are not entirely effective, nor can be successfully applied to all equipment surfaces susceptible to fouling.

3.1.2.2 Groundwater

Groundwater reserves at the site are limited by the nature of the plant location, and lack of hydraulic connection with groundwater resources on properties outside of plant controlled lands.

DCPP has one active permitted deep well (Deep Well #2) located south of Diablo Creek in the Diablo Mesa area. This well supplies water to the makeup water system, which includes supplying the Raw Water Storage Reservoir used primarily for fire water and domestic drinking water. This well is permitted through the San Luis County Health Department. Until 2008, two adjacent Ranney wells were available to collect excess water runoff from Diablo Creek. The Ranney wells have been abandoned. Conveyance piping and associated pumps were removed. A refurbished Ranney well system, or any other system capable of drawing from Diablo Creek surface waters, will not be installed or used in the future in accordance with the provisions of the Coastal Development Permit for the Replacement Steam Generator Projects conducted during the current licensed period.

Deep Well #2 has a maximum capacity of 170 gpm, and a tested reliable production rate of 150-155 gpm that can be maintained even during drought conditions without depleting the taped aquifer. However, the well is not intended to operate continuously, and is only in-service as needed. Average production from the well on an annual basis is projected to be significantly less than 100 gpm during the period of extended operation. The estimate for total well use is approximately 2 weeks (or approximately 350 hours) on average per year at the 150 gpm production rate.

Deep Well #2 will normally only be used in the event the Seawater Reverse Osmosis (SWRO) Unit freshwater production is insufficient to maintain plant makeup or firewater reserves. This is anticipated to occur only during a non-routine period of unusually high freshwater consumption by Unit 1 and/or Unit 2 (such as an extended dual unit forced outage with Units maintained in hot standby), or during periodic planned or unplanned clearance of the SWRO. SWRO supply is generally only insufficient when the system is unavailable for an extended period of time due to scheduled equipment maintenance, an unplanned equipment failure, or a system trip from a transient event such as electrical power loss or excessive pump backpressures. Continuous use of the well at maximum rated capacity is therefore not anticipated during the period of extended operation. The system will remain a back-up freshwater resource, and be used only infrequently.

3.1.3 RADIOACTIVE WASTE TREATMENT PROCESSES

DCPP uses liquid, gaseous, and solid waste processing systems to collect and treat, as needed, radioactive materials that are produced as a by-product of plant operations. Radioactive materials in liquid and gaseous effluents are reduced to levels as low as reasonably achievable.

Radioactive material in the reactor coolant is the source of most liquid, gaseous, and solid radioactive wastes in light water reactors. Radioactive fission products build up within the fuel as a consequence of the fission process. The fission products are contained within the sealed fuel rods; however, small quantities of radioactive materials may be transferred from the fuel elements to the reactor coolant under normal operating conditions.

Reactor fuel assemblies that have exhausted a certain percentage of their fissile uranium content are referred to as spent fuel. Spent fuel assemblies are removed from the reactor core and replaced by new fuel assemblies during routine refueling outages. The spent fuel assemblies are then stored for a period of time in the spent fuel pool and may later be transferred to dry storage at an onsite Independent Spent Fuel Storage

Installation. DCPP also provides onsite storage of mixed waste, which contain both radioactive and chemically hazardous materials.

Storage of radioactive materials is regulated by the NRC under the Atomic Energy Act of 1954, as amended, and storage of hazardous wastes is regulated by the EPA under the Resource Conservation and Recovery Act of 1976.

Systems used at DCPP to process liquid, gaseous, and solid radioactive wastes are described in the following sections.

3.1.3.1 Gaseous Waste System

The Gaseous Radwaste System (GRS) is designed to process radioactive gases consisting primarily of nitrogen and hydrogen with low levels of oxygen. The gases are collected by the vent header system from various primary and auxiliary systems. Radioactive or potentially radioactive gaseous wastes result from collection of excess cover gas in the liquid holdup tanks, gases stripped from reactor coolant in the boric acid evaporator, degasification in the volume control tank, and cover gas displaced in the pressurizer relief tank and reactor coolant drain tank.

Each Unit's surge tank feeds that Unit's waste gas compressor and/or a shared spare compressor through a pressure control valve set to maintain constant compressor suction pressure. The system is designed such that the shared spare compressor will automatically start if the pressure in the surge tank rises above 3 psig. An oxygen monitor on the moisture separator discharge limits the concentration of oxygen that can be fed to the gas decay tanks. The monitor actuates an annunciator at 2 percent 0_2 concentration and trips the compressors at 4 percent 0_2 concentration.

The gas decay tanks are provided for the holdup of radioactive gases prior to release to the environment. The holdup time required is that which would result in releases that are in compliance with release rate and dose limits. Each gas decay tank may be operated as a cover gas supply for the liquid holdup tanks. Normal coolant letdown then displaces the gases back into the GRS. This process effectively increases the volume of storage available for gaseous holdup.

Each gas decay tank is equipped with a flow control valve connected to the plant vent. The discharge of each valve is routed into a common flow control valve that is key-operated to ensure that no inadvertent venting may take place. Downstream of the key-operated valve is a radiation monitor that controls a downstream control valve. If the activity in the discharging waste gas exceeds its upper limit, the control valve closes, terminating the release. The final processing of waste gas prior to release to the atmosphere is by a high-efficiency particulate air (HEPA) filter located just downstream of the radiation control valve and just upstream of the plant vent.

The sampling system associated with the GRS is used to monitor the hydrogen and oxygen content of the gases in the system. Thirteen sample points exist in this system including all influent sources and each of the gas decay tanks. These sample points may be monitored continuously, or intermittently as required, or grab samples may be taken from manual sample taps. The gas analyzer is equipped with a sample tap for taking bottled samples to undergo radiological testing.

3.1.3.2 Liquid Waste System

Units 1 and 2 share a common Liquid Radwaste System (LRS), except for equipment located inside containment. The common waste system consists of the equipment drain subsystem, floor drain subsystem, chemical drain subsystem, laundry and hot shower and laundry/distillate subsystem, and the demineralizer regenerant subsystem.

The floor drain, chemical drain, laundry/distillate, laundry and hot shower, and demineralizer regenerant subsystems generally collect low radioactivity level liquid wastes. The equipment drain subsystem collects liquids with variable radioactivity levels. The demineralizer regenerant subsystem is also used as backup for the floor drain and equipment drain subsystem.

Following treatment, effluents from the LRS are released to the environment at either of the Units' circulating water system (CWS) discharge structures via the ASW system. The waste liquid releases are diluted in the ASW system and Main CWS flows. Releases require positive operator action, are continuously monitored, and are automatically isolated in the event of a high radiation alarm or a power failure.

A major source of radioactive waste liquids is the reactor coolant system (RCS). The bulk of these wastes are processed and retained within the chemical and volume control system (CVCS), with a fraction being discharged to the LRS.

The concentration of radioactivity in the turbine building drains is expected to be low, even in the event of significant primary-to-secondary steam generator leakage. The radiation concentration and flow of liquid from the turbine building drains are monitored at the oily water separator to verify that there are no unaccounted for or unexpected releases from the turbine building drains. If significant radioactivity is detected coming from the turbine building drains, the discharge can be routed to the LRS for treatment. The monitoring system is in conformance with Regulatory Guide RG 1.21, Revision 0 (Reference 6).

Turbine building sump wastes are normally released to the environment via each Unit's circulating water discharge structure.

Equipment Drain or Closed Drain Subsystem
The closed drain system is so called because drains from equipment are connected directly to the drainage system. Closed drain wastes are not exposed to the atmosphere until they reach their destination. Inside containment closed drain wastes

flow to the reactor coolant drain tank. Closed drainage from equipment in the auxiliary building is collected in the miscellaneous equipment drain tank.

Floor Drains and Open Drain Subsystem
The open drain system drains potentially contaminated areas in the containment buildings and the auxiliary building with equipment that does not normally handle reactor coolant. The piping systems and trenches used in this system are not enclosed.

Inside containment, floor drain wastes are collected in the containment sumps and the reactor cavity sump. Potentially contaminated auxiliary building floor drain wastes are collected in the auxiliary building sump. The uncontaminated floor drains from the auxiliary building drain to other discharge pathways such as the sanitary drainage system, outside, etc.

Chemical Drain Subsystem
Chemical wastes are generated due to routine chemical and radiochemical sampling and analyses. Chemical wastes from both Units drain by gravity to a divided chemical drain tank. When one half of the tank is filled, flow is automatically diverted into the second half. The filled section is recirculated, sampled, and analyzed before further batch processing.

Laundry and Hot Shower, and Laundry/Distillate Subsystem
Laundry and hot shower wastes are generally very low in activity. The laundry and hot shower wastes are generated by laundering contaminated protective clothing and by personnel decontamination. A source of waste is the liquid holdup tank liquid that is processed and drained to the laundry/distillate tank. When a holding tank is filled, the contents are recirculated, sampled, and analyzed before further batch processing or discharge.

Demineralizer Regenerant Subsystem
The demineralizer regenerant subsystem consists of two 15,000 gallon demineralizer regenerant receivers (arranged in parallel) located adjacent to the equipment drain receivers in the auxiliary building. Regeneration wastes from the steam generator blowdown treatment system, deborating demineralizers, or evaporator distillate demineralizers are neutralized by concentrated sulfuric acid or sodium hydroxide in the demineralizer regenerant receivers. After neutralization, the waste is recirculated, sampled and analyzed before further batch processing.

The demineralizer regenerant receivers (formerly called spent regenerant receiver tanks) can also receive equipment or floor drain liquid and function as surge capacity for these systems. In addition, the liquid holdup tank liquid that is processed can be drained to the demineralizer regenerant receivers for additional processing.

3.1.3.3 Solid Waste Processing Systems

The Solid Radwaste System (SRS) is designed to process, package, and store the radioactive wastes generated by plant operations until they are shipped offsite for permanent disposal at a licensed burial facility. The SRS has the following major subsystems: the spent filter/ion exchange media processing system, the spent resin processing system, the spent filter cartridge processing system, the mobile radwaste processing system (MRPS), and the dry active waste processing system.

Spent Resins Processing System
The system for transferring spent resins from any of the ion exchangers to the spent resin storage tanks (SRSTs) consists of 4 separate headers connected to 4 eductors and discharge systems that permit the transfer of resin from any of the 30 ion exchanger units to either of 2 SRSTs. A spent resin sampling system allows for the collection of grab samples as resins enter the SRSTs or while the spent resins are being transferred out of the SRSTs to the MRPS.

All of the equipment associated with this system is potentially highly radioactive. The equipment is located behind shielding, and is approached for operation or maintenance only under the direction of plant radiation protection personnel under the special work permit rules of the plant.

Spent Filter/Ion Exchange Media Processing System
Pressurized air is used to transfer exhausted media from either of the two radwaste media filters to the loadout station to which the MRPS container is connected.

Spent Filter Cartridge Processing System
This system is designed to remove and handle spent filter cartridges generated in the filters of the CVCS, Spent Fuel Storage System, and LRS. The radioactively contaminated spent filter cartridges can be removed from the filter housing or vessels with the operator remaining behind shielding. The spent cartridges are transferred to storage or to the MRPS in shielded transfer casks.

Mobile Radwaste Processing System
The MRPS is a skid-mounted mobile radwaste dewatering/solidification system. It is operated on a batch basis to solidify concentrates, to dewater or solidify spent ion exchange or filtration media, and to encapsulate spent cartridge filters. Waste concentrates are transferred to the MRPS through a flexible connection from the boric acid concentrates loadout station and solidified. Slurries from the media filter vessels are sluiced out to the MRPS and dewatered or solidified. Spent resin slurries are sluiced to the MRPS from the spent resin storage tank and dewatered or solidified. Filter cartridges are transferred to the MRPS container in a shielded spent filter transfer cask, if required. Waste concentrates, ion exchange media, filtration media, and cartridge filters will be dewatered or solidified.

Dry Active Waste Processing System
Potentially radioactive dry wastes are collected at appropriate locations throughout the plant, as dictated by the volume of the wastes generated during operation or maintenance. The wastes are then segregated, processed, and packaged. Compressible dry active wastes may be processed by compaction in either a drum or box compactor. During compaction, the airflow in the vicinity of the compactor is directed by the compactor exhaust fan through a high-efficiency particulate filter before it is discharged.

Large or highly radioactive components and equipment that have been contaminated during reactor operation and that are not amenable to compaction are handled either by qualified plant personnel or by outside contractors specializing in radioactive materials handling, and the components and equipment are packaged in shipping containers of an appropriate size and design.

3.1.4 TRANSPORTATION OF RADIOACTIVE MATERIALS

The shipment of prepacked solid waste from the plant site to burial locations is contracted to firms licensed to transport radioactive material in accordance with applicable Department of Transportation regulations. All shipping containers and transportation casks are in conformance with 49 CFR 171 to 49 CFR 178 and 10 CFR 71, as applicable. On average, DCPP transports approximately 620 ft^3 of radioactive materials offsite annually.

3.1.5 NONRADIOACTIVE WASTE SYSTEMS

Nonradioactive waste is produced from plant maintenance and cleaning processes. Most of these wastes associated with plant operations are from secondary system chemistry control blowdown, condensate regeneration system spent resins and wastewaters, filter backwashes, sludges and other wastes removed from equipment during maintenance, floor and yard drains, and plant site stormwater runoff. Chemical and biocide wastes are produced from pH, scaling, and corrosion controls implemented for various closed-cycle cooling water systems. Water treatment chemical residuals also result from processes to clean and control fouling of the main steam condensers and associated water conduits. Waste liquids are typically combined with cooling water discharges in accordance with the National Pollutant Discharge Elimination System (NPDES) Permit.

Nonradioactive gaseous effluents result from combustion of diesel fuel-oil during maintenance, testing, and operation of the DCPP emergency diesel generators (EDGs). Additionally, a fuel-oil fired auxiliary boiler unit is available to provide steam to heat the plant in the unlikely event of an extended dual Unit outage involving cold shutdown of both Units. The auxiliary boiler is not operated for routine maintenance or testing purposes. Discharge of regulated pollutants from fossil fuel combustion equipment is minimized by use of high grade ultra-low sulfur fuel, and limiting fuel usage and hours of operation in accordance with the San Luis Obispo County Air Pollution Control District

(APCD) requirements. Additionally, emissions equipment operating permits incorporate standards that support local air quality goals.

3.1.6 MAINTENANCE, INSPECTION, AND REFUELING ACTIVITIES

Various programs and activities currently exist at DCPP to maintain, inspect, test, and monitor the performance of plant equipment. These programs and activities include, but are not limited, to those implemented to:

- meet the requirements of 10 CFR 50, Appendix B (Quality Assurance), Appendix R (Fire Protection), and Appendices G and H, Reactor Vessel Materials;
- meet the requirements of 10 CFR 50.55a, ASME Code, Section XI, Inservice Inspection and Testing Requirements;
- meet the requirements of 10 CFR 50.65, the maintenance rule, including the structures monitoring program; and
- maintain water chemistry in accordance with EPRI guidelines.

Additional programs include those implemented to meet DCPP Technical Specifications surveillance requirements, those implemented in response to NRC generic communications, and various periodic maintenance, testing, and inspection procedures. Certain program activities are performed during the operation of the Unit. Others are performed during scheduled refueling outages.

3.1.7 POWER TRANSMISSION LINES

The Final Environmental Statement (FES) (Reference 2) identifies three single-circuit 500 kV and one double-circuit 230 kV transmission lines that were built to supply offsite power to DCPP and to connect DCPP to the electric grid. One double-circuit 230 kV line was connected to an existing Morro Bay-Mesa line 10.25 miles from DCPP with an 80-ft right-of-way width. One single-circuit 500 kV line was connected to the Gates Substation in Fresno County 79 miles from DCPP with a 350-ft right-of-way width. Lastly, two single-circuit 500 kV lines were connected to the Midway Substation in Kern County 84 miles from DCPP with a combined right-of-way width of 400 ft. While originally built specifically to supply offsite power to DCPP and to connect DCPP to the electric grid, these transmission lines are now a critical part of PG&E’s high voltage transmission system, providing other services in addition to those related to DCPP.

Subsequent to the publication of the FES, no additional transmission lines have been built to connect DCPP to the electric grid. Thus, the transmission lines of interest are those specified in the FES. Figure 3.1-6 is a map of the transmission systems of interest.

In total, for the specific purpose of connecting DCPP to the transmission system, PG&E has approximately 170 miles of corridor that occupy approximately 7,500 acres. The corridors pass primarily through foothills and rolling land. In addition, there are parcels of land that are agricultural and forest land. The areas are mostly remote. All lines, except the Morro Bay-Mesa feeder line, cross Highway 101.

The transmission lines were designed in the late 1960s and constructed in the early 1970s, in accordance with the State of California's Rules for Overhead Electric Line Construction (General Order 95, Reference 5) and industry guidance that were current when the lines were built. Ongoing surveillance and maintenance of the transmission facilities ensure continued conformance to design standards. These maintenance practices are described in Section 2.4 and Section 4.13.

3.2 REFURBISHMENT ACTIVITIES

NRC

> “The report must contain a description of…the applicant’s plans to modify the facility or its administrative control procedures…This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…” 10 CFR 51.53(c)(2)
>
> “…The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories… (2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item.” (NRC 1996) (“SMITTR” is defined in NRC 1996 as surveillance, monitoring, inspections, testing, trending, and recordkeeping.)

PG&E has addressed potential refurbishment activities in this environmental report in accordance with NRC regulations and complementary information in the NRC *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) for license renewal (Reference 3). NRC requirements for the renewal of operating licenses for nuclear power plants include the preparation of an integrated plant assessment (IPA) (10 CFR 54.21). The IPA must identify and list systems, structures, and components subject to an aging management review. Items that are subject to aging and might require refurbishment include, for example, the reactor vessel, piping, supports, and pump casings (see 10 CFR 54.21 for details), as well as those that are not subject to periodic replacement.

NRC regulations for implementing the National Environmental Policy Act require license renewal phase environmental reports to describe in detail and assess the environmental impacts of any major refurbishment activities such as planned major modifications to systems, structures, and components or plant effluents [10 CFR 51.53(c)(2)]. Resource categories to be evaluated for impacts of refurbishment include terrestrial resources, threatened or endangered species, air quality, housing, public utilities and water supply, education, land use, transportation, and historic and archaeological resources.

GEIS Table B.2 lists license renewal refurbishment activities that NRC anticipated utilities might undertake. In identifying these activities, the GEIS intended to encompass actions that typically take place only once, if at all, in the life of a nuclear plant. The GEIS analysis assumed that a utility would undertake these activities solely for the purpose of extending plant operations beyond 40 years, and would undertake them during the refurbishment period. The GEIS indicates that many plants will have undertaken various refurbishment activities to support the current license period, but that some plants might undertake such tasks only to support extended plant operations.

The DCPP IPA conducted by PG&E under 10 CFR 54 (included as part of the license renewal application) and the DCPP Plant Betterment Study (Reference 7) have not identified the need to undertake any major refurbishment or replacement actions to maintain the functionality of important systems, structures, or components during the DCPP license renewal period. Although routine plant operational and maintenance activities will be performed during the license renewal period, these activities are not refurbishments as described in Sections 2.4 and 3.1 of the GEIS and will be managed in accordance with appropriate DCPP programs and procedures. These items are typical of those that occur during major refueling outages and the environmental impacts are enveloped by the Final Environmental Statement. Accordingly, PG&E has determined that license renewal regulations in 10 CFR 51.53(c)(3)(ii) do not require PG&E to assess the impact of refurbishment on plant and animal habitats, estimated vehicle emissions, housing availability, land use, public schools, or highway traffic on local highways. (See 10 CFR 51.53(c)(3)(ii)(E), (F), (I), (J), respectively.)

To maintain the functionality of important systems, structures, or components during the current operating period, DCPP completed replacement of the Unit 1 and 2 steam generators in 2008 and 2009. DCPP also replaced the Unit 2 reactor head in 2009. The Unit 1 reactor head is scheduled to be replaced in 2010. This replacement is being completed for the current operating licenses and the environmental impacts are enveloped by the Final Environmental Statement for the current DCPP Operating Licenses.

3.3 PROGRAMS AND ACTIVITIES FOR MANAGING THE EFFECTS OF AGING

NRC

"The report must contain a description of…the applicant's plans to modify the facility or its administrative control procedures…This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…" 10 CFR 51.53(c)(2)

"…The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals, and (2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item." (NRC 1996) ("SMITTR" is defined in NRC 1996 as surveillance, monitoring, inspections, testing, trending, and recordkeeping.)

The IPA required by 10 CFR 54.21 identifies the programs and inspections for managing aging effects at DCPP. These programs are described in Appendix B of the *License Renewal Application, Diablo Canyon Power Plant* to which this Environmental Report is appended.

3.4 EMPLOYMENT

3.4.1 CURRENT WORKFORCE

PG&E employs approximately 1,350 employees at DCPP. This is within the range of 600 to 800 personnel per reactor Unit estimated in the GEIS (Reference 3). Over 95 percent of DCPP employees live in San Luis Obispo County, California and Santa Barbara County. The remaining employees are distributed across 10 other counties in California with numbers ranging from 1 to 7 employees per county. None of the DCPP permanent workforce lives outside of California.

DCPP is on an 18-month refueling cycle. During refueling outages, site employment increases above the permanent workforce by as many as 1,200 for approximately 40 days of temporary duty. This number of outage workers falls within the range (200 to 900 workers per reactor Unit) reported in the GEIS for additional maintenance workers (Reference 3).

3.4.2 LICENSE RENEWAL INCREMENT

Performing license renewal activities could necessitate increasing the DCPP staff workload by some increment. The size of this increment would be a function of the schedule within which PG&E must accomplish the work and the amount of work involved. Because PG&E has determined that no refurbishment is needed (Section 3.2), the analysis of license renewal employment increment focuses on programs and activities for managing the effects of aging (Section 3.3).

The GEIS (Reference 3) assumes that NRC would renew a nuclear power plant license for a 20-year period, plus the duration remaining on the current license, and that NRC would issue the renewal approximately 10 years prior to license expiration. In other words, the renewed license would be in effect for approximately 30 years. The GEIS further assumes that the utility would initiate surveillance, monitoring, inspection, testing, trending, and recordkeeping (SMITTR) activities at the time of issuance of the new license and would conduct license renewal SMITTR activities throughout the remaining 30-year life of the plant, sometime during full-power operation (Reference 3), but mostly during normal refueling and the 5 and 10-year in-service inspection and refueling outages.

PG&E has determined that the GEIS scheduling assumptions are reasonably representative of DCPP incremental license renewal workload scheduling. Many DCPP license renewal SMITTR activities would have to be performed during outages. Although some DCPP license renewal SMITTR activities would be one-time efforts, others would be recurring periodic activities that would continue for the life of the plant.

The GEIS estimates that the most additional personnel needed to perform license renewal SMITTR activities would typically be 60 persons during the 3-month duration of a 10-year inservice inspection and refueling outage. Having established this upper value for what would be a single event in 20 years, the GEIS uses this number as the expected number of additional permanent workers needed per Unit attributable to license renewal. GEIS Section C.3.1.2 uses this approach in order to "…provide a realistic upper bound to potential population-driven impacts…"

PG&E has identified no need for significant new aging management programs or major modifications to existing programs. PG&E anticipates that existing "surge" capabilities for routine activities, such as refueling outages, will enable PG&E to perform the increased SMITTR workload without increasing DCPP staff. Therefore, PG&E has no plans to add non-outage employees to support DCPP operations during the license renewal term. PG&E believes that increased SMITTR tasks can be performed within this schedule and employment level. Therefore, PG&E has no plans to provide additional refueling outage employees for the license renewal term.

3.5 REFERENCES

1. Diablo Canyon Power Plant Units 1 & 2 Final Safety Analysis Report Update, Revision 18, Pacific Gas and Electric Company, October 2008.

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

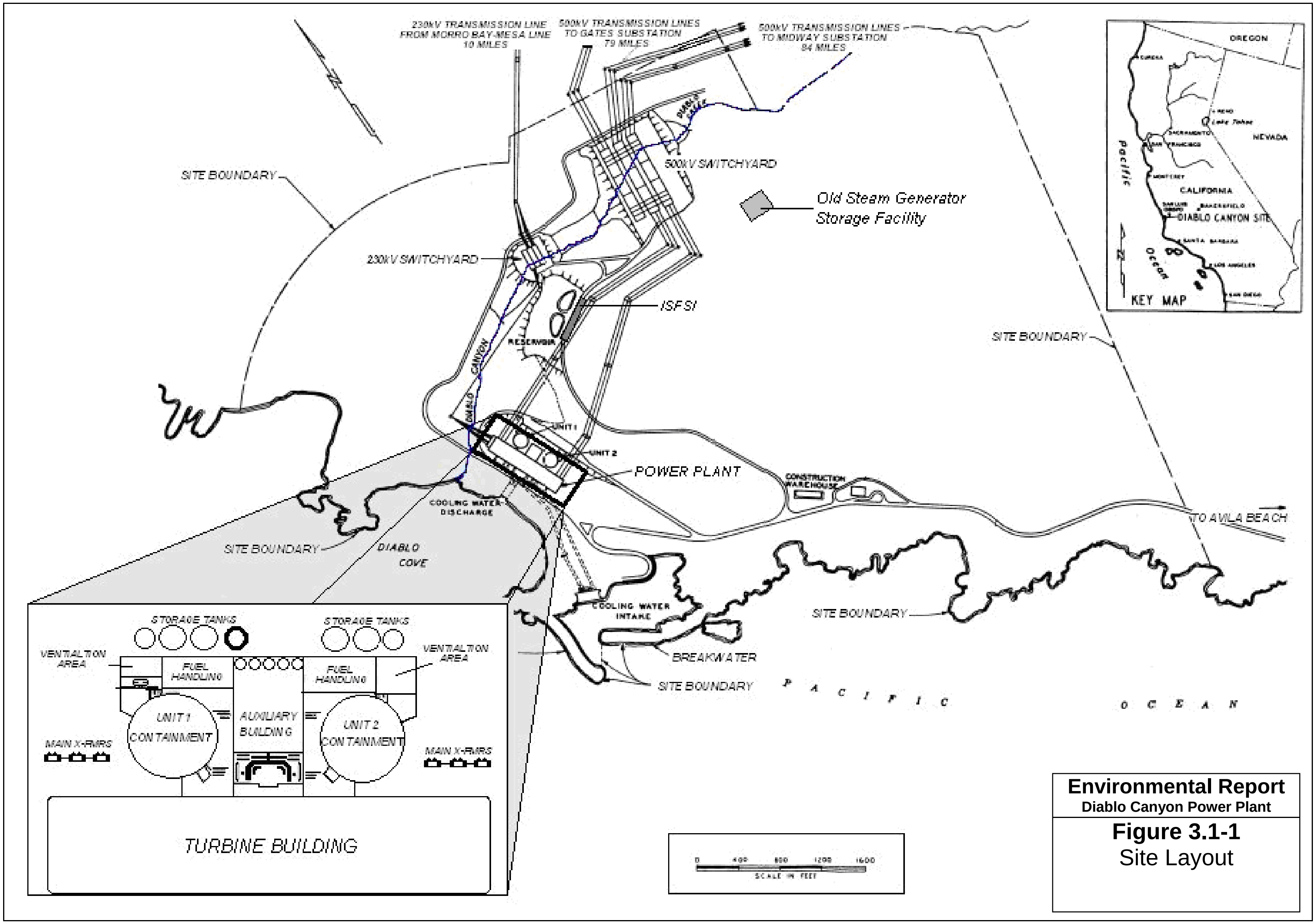
3. NUREG-1437: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS), Volumes 1 and 2. U.S. Nuclear Regulatory Commission. Washington, D.C. May 1996.

4. Final Environmental Impact Report: Diablo Canyon Power Plant Steam Generator Replacement Project. Prepared by Aspen Environmental Services for Pacific Gas and Electric Company. 2005.

5. State of California's Rules for Overhead Electric Line Construction: General Order 95. Prescribed by the Public Utilities Commission of the State of California

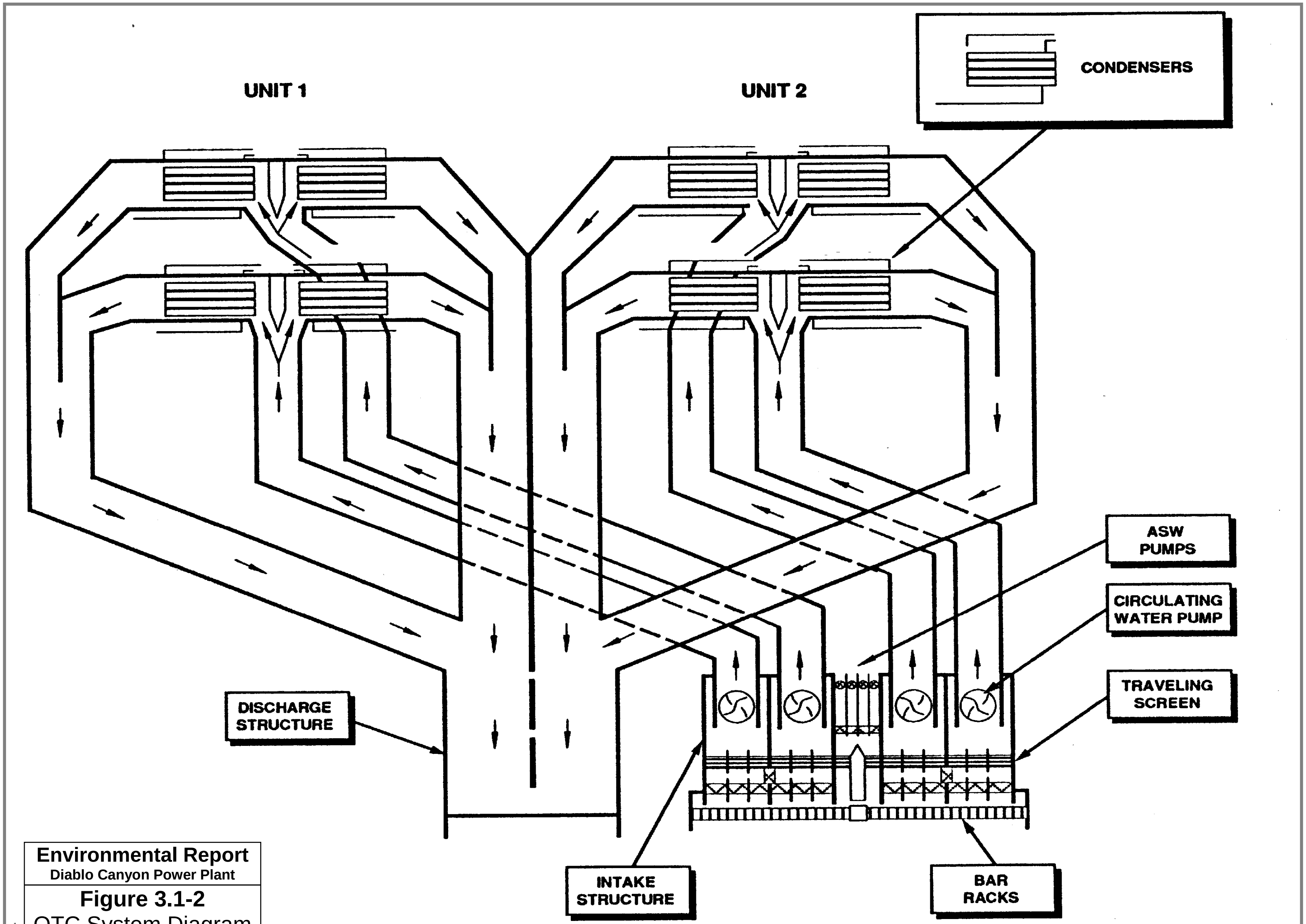
6. Regulatory Guide 1.21: Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-water-cooled Nuclear Power Plants, U.S. Nuclear Regulatory Commission. Washington, D.C., December 1971.

7. Plant Betterment Study. Pacific Gas and Electric Company. Revision 0. September 2009.

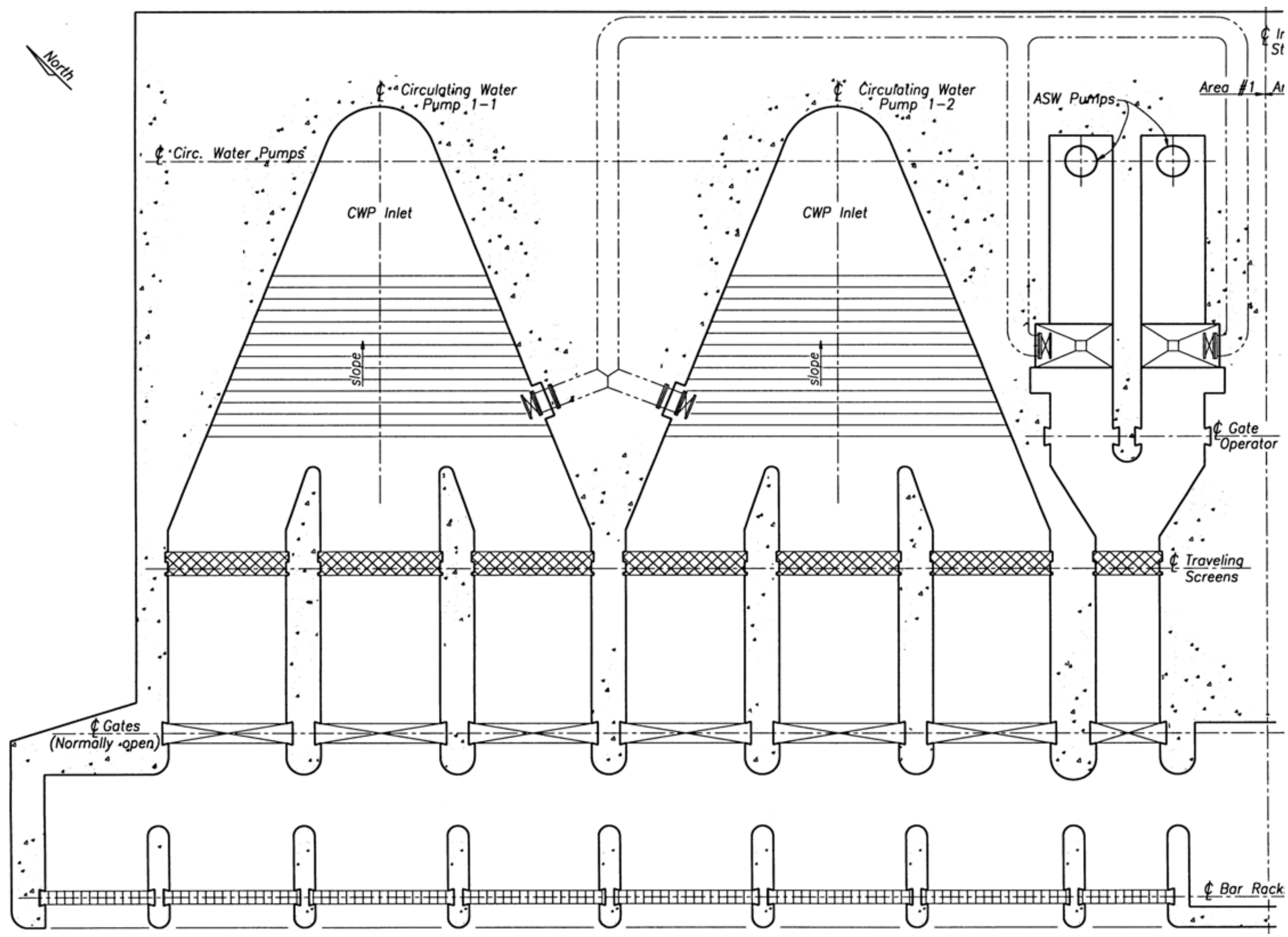


Environmental Report
Diablo Canyon Power Plant

Figure 3.1-1
Site Layout

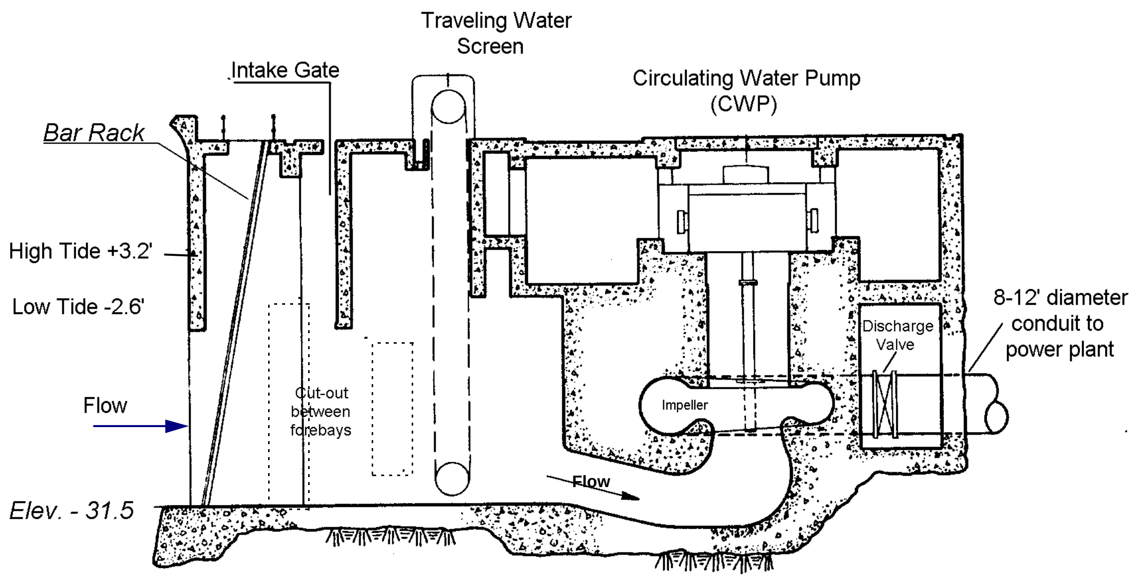


Environmental Report
Diablo Canyon Power Plant
Figure 3.1-2
OTC System Diagram

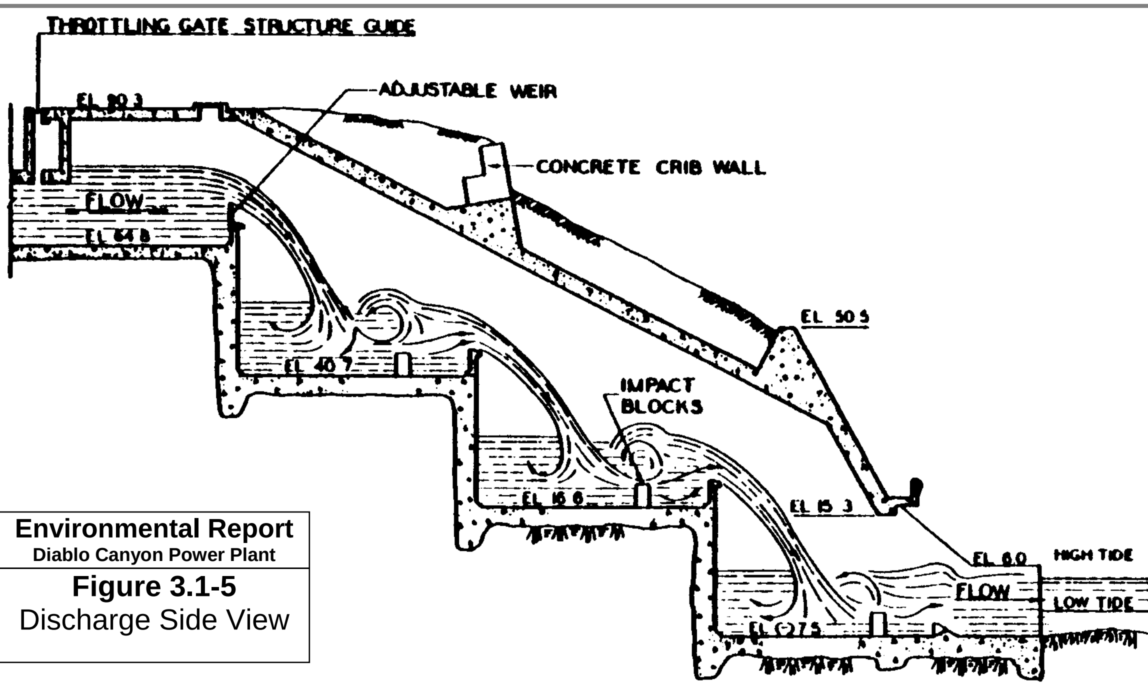


Environmental Report
Diablo Canyon Power Plant

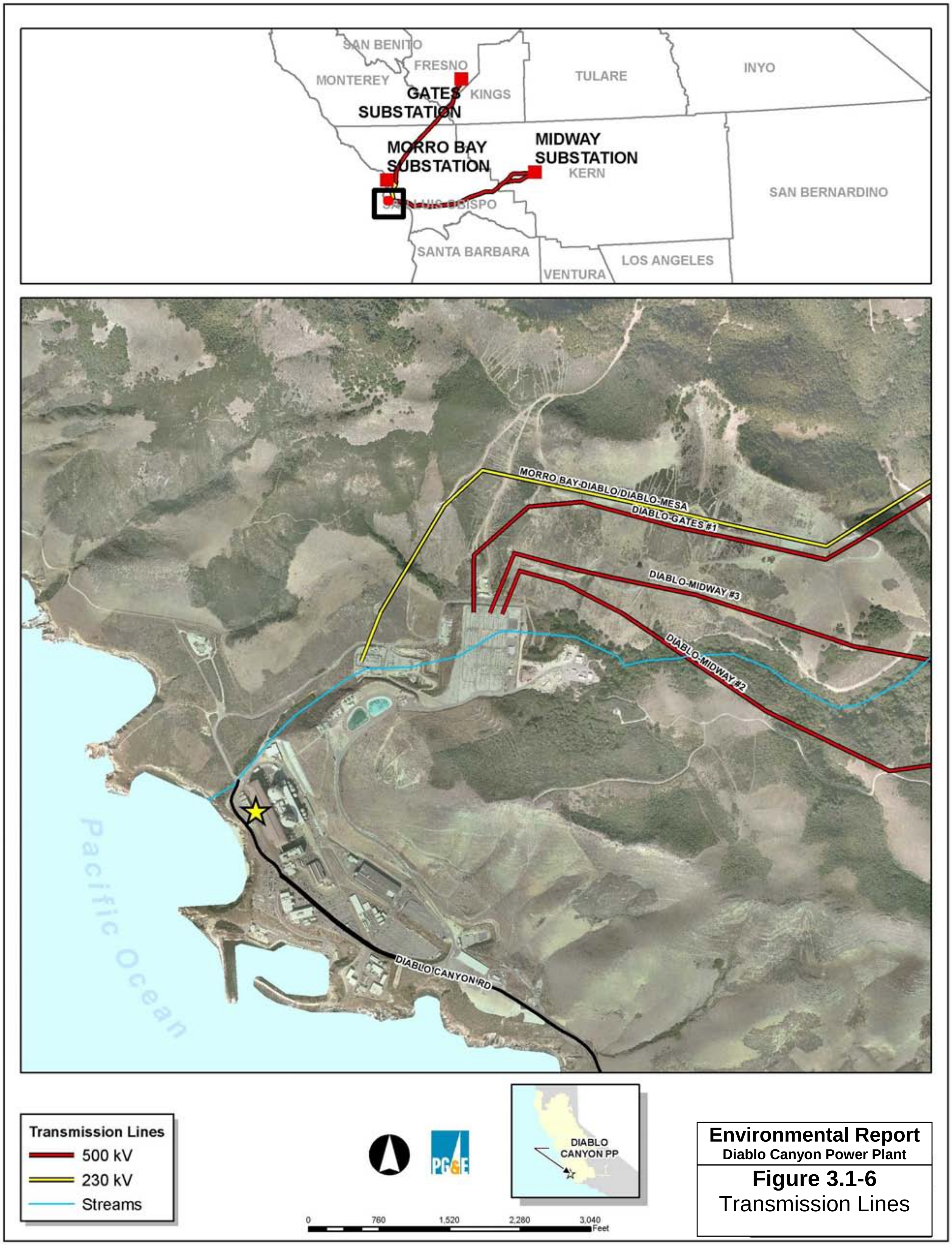
Figure 3.1-3
Unit-1 Intake Bays



Environmental Report
Diablo Canyon Power Plant
Figure 3.1-4
Intake Side View



Environmental Report
Diablo Canyon Power Plant
Figure 3.1-5
Discharge Side View



Environmental Report
Diablo Canyon Power Plant
Figure 3.1-6
Transmission Lines

CHAPTER 4 - ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION AND MITIGATING ACTIONS

NRC

"The report must contain a consideration of alternatives for reducing adverse impacts…for all Category 2 license renewal issues…." 10 CFR 51.53(c)(3)(iii)

"…The environmental report shall include an analysis that considers…the environmental effects of the proposed action…and alternatives available for reducing or avoiding adverse environmental effects.…" 10 CFR 51.45(c) as adopted by 10 CFR 51.53(c)(2) and 10 CFR 51.53(c)(3)(iii)

The environmental report shall discuss "The impact of the proposed action on the environment. Impacts shall be discussed in proportion to their significance;" 10 CFR 51.45(b)(1) as adopted by 10 CFR 51.53(c)(2)

"…The information submitted…should not be confined to information supporting the proposed action but should also include adverse information." 10 CFR 51.45(e) as adopted by 10 CFR 51.53(c)(2)

Chapter 4 presents an assessment of the environmental consequences and potential mitigating actions associated with the renewal of the Diablo Canyon Power Plant (DCPP) operating license. The NRC has prepared a *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (Reference 18), which identifies and analyzes 92 environmental issues that the NRC considers to be associated with nuclear power plant license renewal. In its analysis, the NRC designated each of the 92 issues as Category 1, Category 2, or NA (not applicable) and required plant-specific analysis of only the Category 2 issues.

The NRC designated an issue as Category 1 if, based on the result of its analysis, the following criteria were met:

- the environmental impacts associated with the issue have been determined to apply either to all plants or, for some issues, to plants having a specific type of cooling system or other specified plant or site characteristic,

- a single significance level (i.e., small, moderate, or large) has been assigned to the impacts that would occur at any plant, regardless of which plant is being evaluated (except for collective offsite radiological impacts from the fuel cycle and from high-level waste and spent fuel disposal), and

- mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are likely to be not sufficiently beneficial to warrant implementation.

Absent new and significant information (Chapter 5), the NRC rules do not require analyses of Category 1 issues because the NRC resolved them using generic findings presented in 10 CFR 51, Appendix B, Table B-1. An applicant may reference the generic findings or GEIS analyses for Category 1 issues.

If the NRC analysis concluded that one or more of the Category 1 criteria could not be met, the issue was assigned as Category 2. The NRC requires plant-specific analyses for Category 2 issues. The NRC designated 2 issues as “NA” (Issues 60 and 92), signifying that the categorization and impact definitions do not apply to these issues. Attachment A of this report lists the 92 issues and identifies the environmental report section that addresses each issue and, where appropriate, references supporting analyses in the GEIS.

Category 1 License Renewal Issues

NRC

> “The environmental report for the operating license renewal stage is not required to contain analyses of the environmental impacts of the license renewal issues identified as Category 1 issues in Appendix B to subpart A of this part.” 10 CFR 51.53(c)(3)(i)
>
> “…[A]bsent new and significant information, the analysis for certain impacts codified by this rulemaking need only be incorporated by reference in an applicant’s environmental report for license renewal….” (NRC 1996)

Pacific Gas and Electric Company (PG&E) has determined that, of the 69 Category 1 issues, 10 do not apply to DCPP because they apply to design or operational features that do not exist at the facility. In addition, because PG&E does not plan to conduct any major refurbishment activities, the NRC findings for the 7 Category 1 issues that pertain only to refurbishment do not apply to this application. PG&E has reviewed the NRC Category 1 findings and has identified no new and significant information that would make the NRC findings inapplicable to DCPP. Therefore, PG&E adopts by reference the NRC findings for these Category 1 issues.

Category 2 License Renewal Issues

NRC

> “The environmental report must contain analyses of the environmental impacts of the proposed action, including the impacts of refurbishment activities, if any, associated with license renewal and the impacts of operation during the renewal term, for those issues identified as Category 2 issues in Appendix B to subpart A of this part….” 10 CFR 51.53(c)(3)(ii)
>
> “The report must contain a consideration of alternatives for reducing adverse impacts, as required by § 51.45(c), for all Category 2 license renewal issues….” 10 CFR 51.53(c)(3)(iii)

The NRC designated 21 issues as Category 2. Sections 4.1 through 4.20 address each of these issues (Section 4.17 addresses 2 issues), beginning with a statement of the issue. As is the case with Category 1 issues, 6 Category 2 issues apply to operational features that DCPP does not have. In addition, 8 Category 2 issues apply only to refurbishment activities or to scenarios involving additional employment for managing plant aging. PG&E does not plan any refurbishment or additional employment. If an issue does not apply to DCPP, the section explains the basis for inapplicability.

For the 7 Category 2 issues that PG&E has determined to be applicable to DCPP, analyses are provided. These analyses include conclusions regarding the significance of the impacts relative to the renewal of the operating license for DCPP and, when applicable, discuss potential mitigative alternatives. PG&E has identified the significance of the impacts associated with each issue as either Small, Moderate, or Large, consistent with the criteria that the NRC established in 10 CFR 51, Appendix B, Table B-1, Footnote 3 as follows:

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission’s regulations are considered small.

MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.

LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

In accordance with National Environmental Policy Act practice, PG&E considered ongoing and potential additional mitigation in proportion to the significance of the impact to be addressed (i.e., impacts that are small receive less mitigative consideration than impacts that are large).

"NA" License Renewal Issues

The NRC determined that its categorization and impact-finding definitions did not apply to two issues (Issues 60 and 92); however, PG&E included these issues in Attachment A. Applicants currently do not need to submit information on chronic effects from electromagnetic fields (10 CFR 51, Appendix B, Table B-1, Footnote 5). For environmental justice, the NRC does not require information from applicants, but noted that it will be addressed in individual license renewal reviews (10 CFR 51, Appendix B, Table B-1, Footnote 6). PG&E has included minority and low-income demographic information in Section 2.6.2.

4.1 WATER USE CONFLICTS (PLANTS WITH COOLING PONDS OR COOLING TOWERS USING MAKEUP WATER FROM A SMALL RIVER WITH LOW FLOW)

NRC

"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3 / year (9×10^{10} m^3 / year), an assessment of the impact of the proposed action on the flow of the river and related impacts on instream and riparian ecological communities must be provided. The applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow." 10 CFR 51.53(c)(3)(ii)(A)

"…The issue has been a concern at nuclear power plants with cooling ponds and at plants with cooling towers. Impacts on instream and riparian communities near these plants could be of moderate significance in some situations.…" 10 CFR 51, Subpart A, Table B-1, Issue 13

The NRC made surface water use conflicts a Category 2 issue because consultations with regulatory agencies indicate that water use conflicts are already a concern at two closed-cycle plants and may be a problem in the future at other plants. In the GEIS, the NRC notes two factors that may cause water use and availability issues to become important for some nuclear power plants that use cooling towers. First, some plants equipped with cooling towers are located on small rivers that are susceptible to droughts or competing water uses. Second, consumptive water loss associated with closed-cycle cooling systems may represent a substantial proportion of the flows in small rivers (Reference 18).

This issue does not apply to DCPP because, as indicated in Section 3.1.2, DCPP does not use cooling ponds or cooling towers, or withdraw water from a small river. DCPP uses a once-through cooling system that withdraws water from and discharges water to the Pacific Ocean.

4.2 ENTRAINMENT OF FISH AND SHELLFISH IN EARLY LIFE STAGES

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations…or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from …entrainment."
10 CFR 51.53(c)(3)(ii)(B)

"…The impacts of entrainment are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. Further, ongoing efforts in the vicinity of these plants to restore fish populations may increase the numbers of fish susceptible to intake effects during the license renewal period, such that entrainment studies conducted in support of the original license may no longer be valid…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 25

The NRC made impacts on fish and shellfish resources resulting from entrainment a Category 2 issue, because it could not assign a single significance level (small, moderate, or large) to the issue. The impacts of entrainment are small at many facilities, but may be moderate or large at others. Also, ongoing restoration efforts may increase the number of fish susceptible to intake effects during the period of extended operation (Reference 18). Accordingly, the NRC must determine the type of cooling system (whether one-through or cooling pond) and the status of any Clean Water Act Section 316(b) determination or equivalent state documentation.

DCPP has a once-through heat dissipation system that withdraws from and discharges to the Pacific Ocean. The general design and operational parameters of the cooling system are provided in Section 3.1.2.

The NRC has indicated in the GEIS for license renewal (Reference 18) that issuance of a National Pollutant Discharge Elimination System (NPDES) Permit implies certification by the State. Consistent with the GEIS, PG&E provides the current, enforceable, DCPP NPDES Permit No, CA0003751, Order 90-09, as evidence of Water Quality Certification under Clean Water Act (CWA) Section 401 (CCRWQCB, 1990) (see Attachment B). The permit issued to PG&E specifically states that the location, design, construction and capacity of cooling water intake structures at DCPP reflect the Best Technology Available (BTA) for minimizing adverse environmental impact under 316(b). The permit was due to expire in 1995, and has since been in administrative extension. PG&E is actively working with the Central Coast Regional Water Quality Control Board

(CCRWQCB) to renew the permit. The current permit does not include any requirements for ongoing entrainment monitoring during power plant intake operations.

The significance of entrainment losses for early life stages of marine organisms as well as cooling system discharge thermal impacts have been the subject of discussions between PG&E and the regulatory agency directly responsible for authorization and enforcement of plant specific NPDES requirements. The issues have resulted in extensive communications and consultations between PG&E and the CCRWQCB. Other state agencies have also been involved in permit related consultations, including the California State Water Resources Control Board (SWRCB) and the California State Department of Fish and Game (CDF&G). The nature of these communications and consultations are provided in the references for this Section and Section 4.4, Heat Shock.

A summary of entrainment specific issues is provided in this section and the accompanying technical data report (Reference 10). Issues related to thermal discharge are discussed in Section 4.4. PG&E anticipates that final resolution of all outstanding issues for both entrainment and thermal discharge impacts will occur during the current operating license period, and PG&E will be issued renewed NPDES permits prior to the period of extended operation.

The primary issue regarding entrainment is whether or not the absolute loss of larval organisms or eggs due to power plant cooling system operations constitutes an adverse environmental impact regardless of whether or not those losses result in degradation of the overall health of the aquatic ecosystem. The regulatory community, including the CCRWQCB, has promoted the viewpoint that absolute losses are an adverse impact regardless of the presence or absence of detectable population level effects in the environment, and therefore entrainment reduction or mitigation measures may be warranted under any circumstances. This has been a general issue throughout the electric power generation industry, as well as an issue of relevance regarding continued use of once-through cooling (OTC) systems at existing nuclear power plants that have applied for license renewal. Generically, operators of facilities with OTC systems support the interpretation that observable population or ecological level effects are the appropriate indicator of whether or not entrainment losses result in adverse environmental impacts. This issue continues to be discussed among the generation industry and components of the regulatory community. Final resolution of issues related to the significance of entrainment impacts for DCPP are pending, and current issues regarding continued use of OTC have the potential to remain open for an extended period of time.

Regarding the impacts of entrainment of phytoplankton and zooplankton, because of the large numbers and short regeneration times of plankton, and generally ubiquitous dispersion of these organisms in both nearshore and offshore marine habitat, localized entrainment impacts are considered to be of little ecological consequence. Further, any potential effects from entrainment losses at a specific location would also not be expected to contribute to detectable cumulative impacts in a nearshore region because the regeneration times of remaining non-entrained plankton are so rapid.

PG&E anticipates continued operation of the existing OTC system at DCPP during the period of extended operation. This is consistent with determinations regarding use of the installed cooling system within the Final Environmental Statement (FES) for the initial operating license period. As such, the Environmental Report and the conclusions of individual assessments related to Aquatic Ecology are predicated on the continued exclusive use of OTC. Issues specific to NPDES Permitting of the cooling system are expected to be resolved through the jurisdictional regulatory authority and associated processes for implementation and enforcement of Federal Clean Water Act requirements.

4.2.1 STATUS OF WASTE DISCHARGE REQUIREMENTS PERMIT

Commercial plant operations began in May 1985 with cooling system wastewater discharges authorized under NPDES Permit No. CA0003751 Permit Order 82-54 as amended April 1983. In August 1985, the CCRWQCB issued modified NPDES Permit Order No. 85-101. DCPP then applied for renewal of the permit, as required, prior to expiration of Order No. 85-101.

NPDES Permit No. CA0003751 Order 90-09, for DCPP Units 1 and 2, was adopted by the CCRWQCB on May 11, 1990 with an expiration date of July 1, 1995. In accordance with Federal and State regulations (and Order 90-09 Section D. Provisions, Subsection 9), an application was submitted by PG&E for a new permit 180-days prior to the expiration of Order 90-09 on November 7, 1994, and all applicable application fees paid.

PG&E was notified on June 26, 1995 by the CCRWQCB that a timely and complete application for re-issuance of Permit No. CA0003751 was received, and pursuant to 40 Code of Federal Regulations (CFR) Part 122.6, the existing permit order would remain valid, enforceable, and fully effective until January 1, 1997 (Reference 2). Renewal of the permit was deferred pending preparation of a comprehensive final report assessing adequacy of the existing discharge thermal limits. Recommendations were being considered by the CCRWQCB to modify the permit monitoring and reporting program, and a multi-agency workgroup was established to advise on the development of the comprehensive thermal effects assessment. These various efforts significantly impacted advancement of the permit renewal process

On August 29, 1996, PG&E was informed in a letter from the CCRWQCB that under the authority of California State Code of Regulations (CCR) Title 23, Section 2235.4, the existing NPDES Permit Order (90-09) would remain valid until a new permit was issued provided the facility complied with all requirements of the permit (Reference 3). Renewal of the permit continued to be deferred pending further development of the comprehensive thermal impacts assessment, as well as initiation and completion of a 316(b) demonstration study developed and implemented under the direction of a technical work group coordinated by CCRWQCB staff. The thermal assessment and

316(b) demonstration study were subsequently completed, and reports submitted to the CCRWQCB.

PG&E submitted an amended application for renewal of waste water discharge requirements under Permit No. CA0003751 to the CCRWQCB on January 24, 2001. A hearing was conducted on July 23, 2003 to consider adoption of a renewed permit for DCPP Units 1 and 2. The draft updated permit was not adopted, and additional evaluations and analysis, primarily concerning alternative potential mitigation strategies to compensate for entrainment losses, were requested by the CCRWQCB. The agency subsequently directed a team of independent consultants to consider and develop mitigation strategies for entrainment. The consultant's draft report was presented to the CCRWQCB in a public hearing that took place in September of 2005. The draft report concluded that construction of a large scale artificial reef in the ocean could provide an acceptable mitigation strategy to provide in-kind compensation for larval organisms and egg loss due to operation of the power plant cooling system. Construction and management of such a structure in the ocean however would likely result in project costs far in excess of the monetized losses caused by plant entrainment.

No further CCRWQCB-initiated activities related to renewal of the DCPP NPDES permit have occurred subsequent to the 2005 hearing. Current deferral of action has primarily been due to development and subsequent litigation surrounding the US EPA Phase II Rule for regulation of impingement and entrainment (I&E) at existing power plants using OTC. Varied methods of facility compliance provided in the initial 2004 Phase II Rule were legally challenged. The Federal Second Circuit Court subsequently remanded substantial components of the rule back to US EPA in the 2007 "*Riverkeeper II*" decision, as well as determined that costs of compliance options versus benefits gained were not an appropriate consideration when developing compliance strategies or assessing rule applicability. The cost benefit portion of *Riverkeeper II* was then subsequently appealed to the US Supreme Court. The US Supreme Court ruled on April 1, 2009 that cost versus benefit evaluations can be used as a component of Federal EPA rule making, specifically as it relates to the development of I&E regulations. Development and issuance of a modified Phase II Rule by the EPA is pending.

In addition to the outstanding issues involving a final Phase II Rule, the California SWRCB developed a draft State Policy in 2008 to standardize implementation of I&E regulations by the various Regional Water Quality Control Boards, including the CCRWQCB that oversees the DCPP NPDES Permit. The draft state policy includes stringent requirements to implement significant I&E reductions at existing power plants along the California Coast. The draft policy effectively directs facilities to implement I&E reductions commensurate with closed-cycle cooling (retrofit to cooling towers) regardless of cost or technical feasibility, or cease operations. However, the draft policy did not fully account for all relevant issues involving economics, feasibility of obtaining permits or licenses to implement facility modification or replacement, other adverse environmental impacts that would result from policy implementation, or the overall effects of the policy on the State's electric generation resources. Further development of the policy is anticipated to include input from an inter-agency process that will facilitate review and consideration of those issues the initial draft did not adequately address. Additionally, a State-specific policy will likely remain incomplete pending the development of revised Federal Phase II Rule. The CCRWQCB has therefore effectively postponed further evaluation of completing renewal of the DCPP NPDES Permit pending further actions at both the Federal and State level regarding I&E regulations for existing OTC facilities.

Pending full resolution of outstanding regulatory issues involving I&E, and subsequent final approval of a revised permit, the existing NPDES Permit No. CA0003751 Order 90-09 remains current and enforceable for DCPP Units 1 and 2.

4.2.2 ONCE-THROUGH COOLING (OTC) SYSTEM

Section 3.1.2 provides a general description of the DCPP OTC system. During full power operations, the plant circulates approximately 2.45 billion gallons (equivalent to 9.275 million cubic meters) of raw seawater per day through the main steam condensers. Intake is from the Pacific Ocean at ambient temperature, and discharge is returned to the Ocean approximately 20^{o}F on average above ambient.

The 3/8-inch mesh traveling debris screens located at the intake structure do not filter out or impinge microscopic phytoplankton and zooplankton, or the eggs and larval of the vast majority of marine fish and shellfish present in the source water body susceptible to entrainment in the cooling water flow. Microscopic and small organisms carried in the flow pass unobstructed through the mesh. These entrained organisms are then subjected to pumping forces, exposure to macro-fouling cropping within the system (primarily filter feeding barnacles and mussels that populate the seawater conduit surfaces), rapid thermal change passing through the main steam condensers, and significant turbulence during discharge back to the Pacific Ocean.

No specific technological or operational methods are employed to reduce entrainment of fish and shellfish larvae or eggs. Losses for entrained fish and shellfish are administratively set by agreement between PG&E and the CCRWQCB at 100 percent when considering entrainment impacts caused by cooling system operations. Actual losses for hard bodied more-durable organisms are likely much lower than 100 percent. Soft bodied organisms such as fish larvae, however, may in fact experience relatively low survival rates when transiting the system.

The abundance and diversity of organisms present at any given time in the intake water column, oceanographic and operational conditions, and the state of system conduit macro fouling will affect actual entrainment losses during plant operations at any given time. Regardless, for all regulatory and assessment purposes, entrainment losses caused by DCPP are considered 100 percent of all organisms withdrawn form the Pacific Ocean with the intake flow under all conditions.

4.2.3 EVALUATION OF PLANT INTAKE ENTRAINMENT AND IMPACTS

The aquatic ecosystem in the vicinity of DCPP has been extensively studied and monitored both prior to operation of the plant, and throughout commercial operations. DCPP has been the subject of an extensive marine ecological impacts assessment. These studies have included extensive pre-operational evaluation and modeling, and post-operational monitoring, of the impacts from thermal discharge to the Pacific Ocean receiving waters at Diablo Cove. During operations, extensive monitoring has also been conducted on ambient control areas North and South of the facility. The detailed monitoring has provided direct assessments of the abundance of multiple species of organisms over the operational life of the facility which provides evidence regarding population level impacts from cooling system entrainment. The details of thermal discharge assessment studies are included in Section 4.4.

In addition to thermal impacts assessments, an extensive three-year long evaluation of plant entrainment and source water body fish and shellfish larval diversity and abundance was conducted from 1996-1999. The details of design, implementation, study area, and the conclusions of this study are provided in the 316(b) Demonstration Study Report (Reference 15). Descriptions of the fish and shellfish resources in the vicinity of DCPP susceptible to entrainment, including assessment of adult equivalent losses are also provided in the study report.

The summary conclusion from the extensive entrainment and source water body assessment is that DCPP ‘takes’ on average approximately 11 percent of the larval population susceptible to entrainment (Note: depending on species-specific factors, larval losses are generally greater than or less than 11 percent for individual species affected). Considering the volume of water circulated through DCPP, this results in significant absolute numbers of fish and shellfish larvae lost when the 100 percent administrative mortality estimate is applied. Annual entrainment of larval fish is estimated to range between 1.48 and 1.77 billion, dependent on flow.

Though the absolute numbers are large, it is noteworthy that the natural survival rate for eggs and larvae to juvenile stages is generally <1 percent, and survivorship to adult stage for most species is far less than 1 percent. In terms of natural survivability, the loss of 11 percent of the available larval population on average is not significant in light of the fact that 99 percent or more of larvae normally suffer mortality from natural factors before reaching juvenile stages of development.

Biological compensation can be considered more important to the development and maintenance of a healthy aquatic ecological system than absolute larval numbers. As long as habitat is present that supports successful recruitment and development of organisms from larvae stages to juvenile stages and beyond, available larvae can successfully develop to sustain stable reproductive adult populations. This is especially true for the nearshore rocky aquatic habitat in the area that provides for shelter and foraging for rockfish, sculpins, and cabazon. These fish species are the most prevalent in the vicinity, and therefore are also those most susceptible to entrainment in early life stages.

Therefore, the loss of 11 percent of the larval population on average due to DCPP operations is ultimately compensated for by the remaining 89 percent on average that remain available for recruitment to the habitat present in the vicinity and region of DCPP. The health and viability of habitat immediately surrounding the power plant is shown in the data available from the extensive long-term ecological studies conducted in the vicinity.

During the current period of operation, available data from both DCPP-specific ecological studies, as well as independent studies of regional marine fisheries, provide evidence that local populations of fish susceptible to entrainment in larval stages have remained relatively stable. In general, adult populations of individual species have shown varying declines or increases in abundance overtime that can be attributable to natural variation alone. The conclusion from the extensive data from past and ongoing monitoring has shown that overall population decreases have not occurred, and the local marine ecosystem remains healthy.

DCPP is situated on an isolated stretch of pristine coastline with no other substantial human related influences that could negatively impact the health of the marine environment, with exception of limited commercial or recreational fishing. DCPP has provided a unique setting for the assessment of OTC impacts. The design capacity and actual operation of the facility define DCPP as the largest (by volume of water circulated) OTC system on the Pacific Coast. In addition to relative seclusion, a marine protected area (MPA) exists to the immediate north of the facility, and a 1-mile security exclusion zone has further reduced fishing in the immediate plant vicinity since 2001. The DCPP setting has provided a relatively isolated crucible for assessing population level impacts of the large scale OTC operation.

If DCPP operations were resulting in detrimental impacts to fish and shellfish populations in the vicinity, these impacts should be observable, even apparent, after over 20 years of commercial operations, most of which has been at high capacity factors - essentially maximizing potential ecological impacts. However, population-level impacts have not been detected. An independent study of fisheries catch data has shown that the number of rockfish caught per fisher hour in the vicinity (catch per unit effort) has remained stable, even increasing substantially in several recent seasons, despite the fact that the larvae of rockfish are among the species most susceptible to entrainment by DCPP. This and other similar facts provide direct evidence that entrainment losses are not resulting in population level effects in the area. In summary, "The combination of length-frequency analyses, ETM [*Empirical Transport Model]* estimates, and other corroborating data support the conclusion that the local subpopulations of most nearshore taxa are not experiencing long-term declines in abundance due to entrainment" (Reference 15).

4.2.4 CONSIDERATION OF CUMULATIVE ECOLOGICAL IMPACTS FROM OTC OPERATIONS

Cumulative ecological impacts due to potential for additive (synergistic) impacts caused by entrainment, impingement, and thermal discharge by DCPP have been considered. Cooling system thermal discharge impacts, as described in Section 4.4, are isolated to a relatively small geographic location (Diablo Cove) influenced directly by the thermal plume. Extensive thermal monitoring programs implemented throughout the history of the facility have shown that discharge impacts are localized, and do not result in substantial local habitat disruption that would be necessary to cause population level impacts in the greater marine environment - either in the immediate DCPP vicinity or in the region. Degraded ecosystems and subsequent loss of species productivity and abundance can often be attributable to extensive losses of habitat available for larval recruitment and subsequent juvenile stage to adult development for multiple species. The limited/localized influence of the thermal discharge on the expansive rocky intertidal and rocky subtidal habitat running along the coast surrounding DCPP does not support any conclusion that thermal impacts cause population levels effects, or any detrimental effects outside of the limited area directly influenced by the plume.

Impingement impacts from DCPP operations are discussed in Section 4.3. Fish and shellfish biomass trapped on debris screens due to cooling system flow and subsequently lost is very small both in absolute numbers, as well as when considered in respect to the large volumes of water withdrawn by the plant intake. Population level impacts cannot be caused by DCPP impingement, because impingement losses themselves are insignificant.

Entrainment impacts may be less localized and have the potential to influence biological populations throughout the source water area. Due to the limited extent of DCPP's thermal impact, and the design features that result in a small level of impingement, cumulative impacts on populations in the vicinity are expected to primarily reflect impacts that result from entrainment. Entrainment impacts have not been shown to result in detectible population level effects in the vicinity of DCPP or in the region. Therefore, a conclusion can be drawn that cumulative impacts from entrainment, impingement, and thermal discharge are likewise not significant

4.2.5 TECHNOLOGY OR MITIGATION MEASURES TO REDUCE ENTRAINMENT LOSSES

There have been no specific measures implemented during the initial operating license period to reduce the potential adverse impacts of entrainment. As previously discussed, no population level or ecological system level adverse impacts have been identified. The CCRWQCB has previously determined that the loss of larval organisms alone may constitute an adverse impact; however, this same Agency also determined that "Regarding entrainment of larvae in the cooling water system, the proportional loss of larvae is significant. However, the costs of DCPP modifications or operational changes are wholly disproportionate to the benefit to be gained." (Reference 4)

Consideration of technology or mitigation measures that have the potential to reduce or offset entrainment losses from DCPP OTC system operations are detailed in the supporting references for this report section.

No available technologies, other than retrofitting DCPP to closed-cycle cooling, have been identified that could appreciably reduce entrainment losses from cooling system operations. However, retrofitting DCPP to a closed-cycle cooling system is only a conceptual possibility, and would require implementation of a project at an unprecedented scale compared to any other similar undertaking previously conducted in the power generation industry. Additionally, evaluation of retrofitting DCPP has determined that likely insurmountable site-specific permitting, licensing, technical, and economic factors make such a project essentially infeasible. There are no technology or mitigation measures available in which the costs of implementation would not be very significant in relation to potential benefits that could be gained (Reference 19).

It is unknown if implementation of any mitigation strategy, if required, during the period of extended operation would reduce ongoing DCPP entrainment. Any effort to increase the abundance of larvae in the source water body (such as the CCRWQCB consultant's proposal to establish an artificial reef in the vicinity of DCPP) could cause an increase in the abundance of larval populations susceptible to entrainment (Reference 4). Increases in abundance in the source water body could result in related increases in the absolute number of larvae drawn into the cooling system within a given volume of water. However, such increased absolute losses would likely translate to similar percentage losses as those now experienced, ultimately not changing the relative larval 'take' and/or impact of the power plant due to entrainment. As population level impacts attributable to entrainment are currently not witnessed, similarly none would be anticipated if any specific mitigation strategy was implemented in the vicinity.

4.2.6 CONCLUSION - IMPACTS ON FISH AND SHELLFISH RESOURCES RESULTING FROM ENTRAINMENT DURING THE PERIOD OF EXTENDED OPERATION

PG&E anticipates that current uncertainty regarding final regulatory policies regarding reduction or mitigation requirements for absolute entrainment losses resulting from power plant cooling system operations will be resolved through ongoing legislative and administrative processes, and ultimately the existing OTC system will continue to be considered best technology available for DCPP due to site specific considerations.

It is unknown currently what type of mitigation would ever be required for cooling system entrainment during a period of extended operation. In a case in which mitigation would be necessary to offset absolute entrainment losses, the specifics of the mitigation option would be developed and implemented under the guidance of the CCRWQCB as part of the NPDES permitting process.

Based on evidence from the extensive ecological studies conducted during the initial operating license period, entrainment losses of marine organism larvae and/or eggs do not result in observable population level impacts, and subsequently observable detrimental impacts to the overall ecological system susceptible to influence by cooling system withdrawal. Therefore, entrainment impacts to marine fish and shellfish resources from operation of DCPP's OTC system during the period of extended operation are projected to be SMALL.

4.3 IMPINGEMENT OF FISH AND SHELLFISH

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations…or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from…impingement…."
10 CFR 51.53(c)(3)(ii)(B)

"…The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 26

The NRC made impacts on fish and shellfish resources resulting from impingement a Category 2 issue, because it could not assign a single significance level to the issue. Impingement impacts are small at many facilities, but might be moderate or large at other plants (Reference 18). Information that needs to be ascertained includes (1) type of cooling system (whether once through or cooling pond) and (2) a current Clean Water Act 316(b) determination or equivalent state documentation.

DCPP has a once-through heat dissipation system that withdraws from and discharges to the Pacific Ocean. The general design and operational parameters of the cooling system are provided in Section 3.1.2.

As discussed in Section 4.2, the Central Coast Regional Water Quality Control Board (CCRWQCB) issued an NPDES Permit (CA0003751) (see Attachment B) to PG&E in 1990. The permit was due to expire in 1995, and has since been in administrative extension. PG&E is actively working with the CCRWQCB to renew this permit. The current permit does not include any requirements for ongoing impingement monitoring during plant intake operations.

PG&E completed an impingement assessment of the OTC system in 1986. The year long study concluded that impingement of all marine organisms was very low, and further studies have not been warranted. The CCRWQCB determined that "regarding impingement of adult fish in the intake structure, the number of fish lost per year is so minor (a few hundred fish per year) that intake structure modifications or operational changes are not necessary. These losses are already minimized pursuant to Clean Water Act Section 316(b)" (Reference 4).

Impingement losses during full flow intake operations (4 main circulating water pumps and 2 auxiliary water pumps in operation) amount to approximately 2.5 pounds of fish and shellfish biomass daily for a maximum of between 900-1200 pounds of biomass on an annual basis. This is in comparison to intake system performance of other west coast power generation facilities using OTC in which impingement can exceed DCPP's annual biomass total in a single day, even with lower net intake withdrawal volumes at full power. The low impingement rates of the DCPP intake system are attributable to initial design and installation intended to reduce loss of fish due to impingement, as well as placement of the shoreline intake within an engineered protective cove. Refer to the Impingement of Fish and Shellfish Technical Data Report for more information regarding intake structure design, and the results of impingement assessments conducted (Reference 9).

PG&E concludes that impingement impacts to fish and shellfish resources from operation of the OTC system during the period of extended operation, based on the determination of impacts during the initial operating license period, are projected to be SMALL.

4.4 HEAT SHOCK

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act…316(a) variance in accordance with 40 CFR 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock…" 10 CFR 51.53(c)(3)(ii)(B)

"…Because of continuing concerns about heat shock and the possible need to modify thermal discharges in response to changing environmental conditions, the impacts may be of moderate or large significance at some plants…." 10 CFR 51, Subpart A, Table B-1, Issue 27

The NRC made impacts on fish and shellfish resources resulting from heat shock a Category 2 issue because of continuing concerns about thermal discharge effects and the possible need to modify thermal discharges in the future in response to changing environmental conditions (Reference 18). Information to be ascertained includes (1) Type of cooling system (whether once-through or cooling pond), and (2) Evidence of a CWA Section 316(a) variance or equivalent State documentation.

DCPP has a once-through heat dissipation system that withdraws from and discharges to the Pacific Ocean. The general design and operational parameters of the cooling system are provided in Section 3.1.2.

As discussed in Section 4.2, the Central Coast Regional Water Quality Control Board (CCRWQCB) issued an NPDES Permit (CA0003751) (see Attachment B) to PG&E in 1990. The permit was due to expire in 1995 and has since been in administrative extension. PG&E is actively working with the CCRWQCB to renew this permit. In accordance with permit requirements, PG&E monitors discharge characteristics (including heat shock) and reports the results to the CCRWQCB. Refer to the Heat Shock Technical Data Report for more information regarding the history of studies completed for thermal discharge (Reference 7).

The physical characteristics and biological effects of the DCPP thermal discharge have been extensively studied beginning in the mid-1960s when the area was first considered as a power plant site. During plant operations in the initial license period, actual effects of the thermal discharge were found to be only slightly greater in spatial extent than predicted, but are largely confined to the shoreline and shallow areas of Diablo Cove. The most recent completed detailed analysis of the effects of the thermal discharge (Reference 16) showed that the nature and spatial extent of the effects had not increased since the previous assessment detailing changes through 1995 (Reference

14). In general, pre-operational assessments have been confirmed by actual plant operations, and thermal discharge impacts are not significantly changing over time as a result of continued plant operations.

Currently, DCPP is updating the cooling system thermal discharge impacts assessment using data gathered through 2008 from the ongoing Receiving Water Monitoring Program (RWMP). The final report from the effort expands the second operational period (OpPeriod-2) data set used in the last comprehensive analysis (Reference 16) from 1995-2002 to 1995-2008. It is scheduled for completion during 1st Quarter 2010, and preliminary conclusions from the in-progress project are not substantially different from those in the earlier comprehensive reports.

Continued monitoring of the marine environment influenced by the DCPP discharge is anticipated to further support previous conclusions regarding thermal impacts. Once-through cooling system thermal effects are not significantly changing or increasing, and protection of the beneficial uses of the receiving water will continue in the period of extended operation.

PG&E concludes that heat shock impacts to fish and shellfish resources from operation of the OTC system during the period of extended operation, relative to the determinations of thermal discharge impacts during the initial operating license period, are projected to be SMALL.

4.5 GROUNDWATER USE CONFLICTS (PLANTS USING >100 GPM OF GROUNDWATER)

NRC

"If the applicant's plant…pumps more than 100 gallons (total onsite) of ground water per minute, an assessment of the impact of the proposed action on groundwater use must be provided." 10 CFR 51.53(c)(3)(ii)(C)

"…Plants that use more than 100 gpm may cause ground-water use conflicts with nearby ground-water users…." 10 CFR 51, Subpart A, Table B-1, Issue 33

The NRC made this groundwater use conflict a Category 2 issue because at a withdrawal rate of more than 100 gpm, a cone of depression could extend offsite. This could deplete the groundwater supply available to offsite users, creating an impact that could warrant mitigation. Information needed to address this issue includes the DCPP groundwater withdrawal rate (whether greater than 100 gpm), offsite drawdown, and impact on neighboring wells.

Based on information presented in Section 3.1.2, DCPP average[1] groundwater use is less than 100 gpm. Groundwater reserves at the site are limited by the nature of the plant location, and lack of hydraulic connection with groundwater resources on properties outside of plant controlled lands.

DCPP has a groundwater well (Deep Well #2) available as a backup freshwater resource. The deep well has a maximum capacity of 170 gpm, and a tested reliable production rate of 150-155 gpm that can be maintained even during drought conditions without depleting the taped aquifer. However, the well is not intended to operate continuously, and is only in-service as needed. Average production from the well on an annual basis is projected to be significantly less than 100 gpm during the period of extended operation. The estimate for total well use is approximately 2 weeks (or approximately 350 hours) on average per year at the 150 gpm production rate.

Deep Well #2 will normally only be used in the event the Seawater Reverse Osmosis (SWRO) Unit freshwater production is insufficient to maintain plant makeup or firewater reserves. This is anticipated to occur only during a non-routine period of unusually high freshwater consumption by Unit 1 and/or Unit 2 (such as an extended dual unit forced outage with Units maintained in hot standby), or during periodic planned or unplanned clearance of the SWRO. SWRO supply is generally only insufficient when the system is unavailable for an extended period of time due to scheduled equipment maintenance, an unplanned equipment failure, or a system trip from a transient event such as

[1] Regulatory Guide 4.2 Supplement 1 Section 4.5 states that this section is applicable to plants that use more than an *annual average* of 100 gpm. Thus, DCPP's evaluation is based on the annual average use of groundwater.

electrical power loss or excessive pump backpressures. Continuous use of the well at maximum rated capacity is therefore not anticipated during the period of extended operation. The system will remain a back-up freshwater resource, and be used only infrequently.

When in operation, the well draws from an isolated source specific to DCPP. The topography of the location precludes any connection between the well source water and offsite water resources. There are no neighboring wells (outside of the DCPP industrial site and adjacent controlled property) that can be impacted or made unavailable due to operation of the onsite well. Therefore, no cone of depression can be created from groundwater use on the plant site that could extend offsite regardless of pump withdrawal rate or an extended period of withdrawal. Further assessment of the issue of groundwater use conflicts (required for plants using more than 100 gpm groundwater) is not necessary and the impacts of this issue are SMALL.

4.6 GROUNDWATER USE CONFLICTS (PLANTS USING COOLING TOWERS OR COOLING PONDS AND WITHDRAWING MAKEUP WATER FROM A SMALL RIVER)

NRC

"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3 / year...[t]he applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow." 10 CFR 51.53(3)(ii)(A)

"…Water use conflicts may result from surface water withdrawals from small water bodies during low flow conditions which may affect aquifer recharge, especially if other groundwater or upstream surface water users come on line before the time of license renewal…"
10 CFR 51, Subpart A, Table B-1, Issue 34

The NRC made this groundwater use conflict a Category 2 issue because consumptive use of withdrawals from small rivers could adversely impact aquatic life, downstream users of the small river, and groundwater-aquifer recharge. This is a particular concern during low-flow conditions and could create a cumulative impact due to upstream consumptive use. Cooling tower and cooling ponds lose flow due to evaporation, which is necessary to cool the heated water before it is discharged to the environment.

This issue does not apply to DCPP because, as indicated in Section 3.1.2, DCPP does not use cooling towers or cooling ponds, and as of 2008, no longer withdraws water from a small river. DCPP uses a once-through cooling system that withdraws water from and discharges water to the Pacific Ocean.

4.7 GROUNDWATER USE CONFLICTS (PLANTS USING RANNEY WELLS)

NRC

"If the applicant's plant uses Ranney wells…an assessment of the impact of the proposed action on groundwater use must be provided." 10 CFR 51.53(c)(3)(ii)(C)

"…Ranney wells can result in potential ground-water depression beyond the site boundary. Impacts of large ground-water withdrawal for cooling tower makeup at nuclear power plants using Ranney wells must be evaluated at the time of application for license renewal…." 10 CFR 51, Subpart A, Table B-1, Issue 35

The NRC made this groundwater use conflict a Category 2 issue because large quantities of groundwater withdrawn from Ranney wells could degrade groundwater quality at river sites by induced infiltration of poor-quality river water into an aquifer.

This issue does not apply to DCPP because, as indicated in Section 3.1.2, as of 2008, DCPP no longer uses Ranney wells to withdraw water from Diablo Creek. DCPP relies on groundwater obtained from sources (Deep Well #2) other than Ranney wells. DCPP uses a once-through cooling system that withdraws water from and discharges water to the Pacific Ocean.

4.8 DEGRADATION OF GROUNDWATER QUALITY

NRC

"If the applicant's plant is located at an inland site and utilizes cooling ponds, an assessment of the impact of the proposed action on groundwater quality must be provided." 10 CFR 51.53(c)(3)(ii)(D)

"…Sites with closed-cycle cooling ponds may degrade ground-water quality. For plants located inland, the quality of the ground water in the vicinity of the ponds must be shown to be adequate to allow continuation of current uses…" 10 CFR 51, Subpart A, Table B-1, Issue 39

The NRC made degradation of groundwater quality a Category 2 issue because evaporation from closed-cycle cooling ponds concentrates dissolved solids in the water and settles suspended solids. In turn, seepage into the water table aquifer could degrade groundwater quality.

This issue does not apply to DCPP because, as indicated in Section 3.1.2, DCPP does not use cooling water ponds. DCPP uses a once-through cooling system that withdraws water from and discharges water to the Pacific Ocean.

4.9 IMPACTS OF REFURBISHMENT ON TERRESTRIAL RESOURCES

NRC

The environmental report must contain an assessment of "…the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats…." 10 CFR 51.53(c)(3)(ii)(E)

"…Refurbishment impacts are insignificant if no loss of important plant and animal habitat occurs. However, it cannot be known whether important plant and animal communities may be affected until the specific proposal is presented with the license renewal application…."
10 CFR 51, Subpart A, Table B-1, Issue 40

"…If no important resource would be affected, the impacts would be considered minor and of small significance. If important resources could be affected by refurbishment activities, the impacts would be potentially significant…." (NRC 1996)

The NRC made impacts to terrestrial resources from refurbishment a Category 2 issue because the significance of ecological impacts cannot be determined without considering site- and project-specific details (Reference 18). Aspects of the site and project to be ascertained are: (1) the identification of important ecological resources, (2) the nature of refurbishment activities, and (3) the extent of impacts to plant and animal habitats.

The issue of impacts of refurbishment on terrestrial resources is not applicable to DCPP because, as discussed in Section 3.2, PG&E has no plans for refurbishment or other license renewal-related construction activities at DCPP. Beyond impacts from refurbishment, the impacts of current operations have had a small impact on terrestrial ecosystems. The impacts to terrestrial ecosystems from continued plant operations and maintenance are expected to be unchanged and SMALL.

4.10 THREATENED OR ENDANGERED SPECIES

NRC

"Additionally, the applicant shall assess the impact of the proposed action on threatened and endangered species in accordance with the Endangered Species Act." 10 CFR 51.53(c)(3)(ii)(E)

"Generally, plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. However, consultation with appropriate agencies would be needed at the time of license renewal to determine whether threatened or endangered species are present and whether they would be adversely affected." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 49

The NRC made impacts to threatened and endangered species a Category 2 issue because the status of many species is being reviewed continuously, and site-specific assessment is required to determine whether any identified species could be affected by refurbishment activities or continued plant operations through the renewal period. In addition, compliance with the Endangered Species Act requires consultation with the appropriate federal agency (Reference 18, Sections 3.9 and 4.1).

Section 2.2 describes the aquatic communities near the plant site, and discusses population trends in recreationally and commercially important populations. Section 2.4 describes important terrestrial habitats at DCPP. Section 2.5 discusses State and Federally-listed threatened or endangered species that occur or may occur at DCPP, or along associated transmission corridors.

PG&E is currently unaware of any adverse issues that involve State and Federally-listed threatened or endangered species associated with the operation and/or maintenance of DCPP, including the existing transmission lines, towers, and access roads. PG&E corresponded with appropriate agencies (FWS, SLC, BLM, NMFS, and CDFG) requesting information on the role each agency would expect to play in the license renewal process and the scope of information that may be required to fulfill those responsibilities. Agency consultation correspondence is provided in Attachment C.

As discussed in Section 3.2, PG&E has no plans to conduct refurbishment activities at DCPP during the license renewal term. Therefore, there would be no refurbishment-related impacts to special-status species and no further analysis of refurbishment-related impacts is warranted. Furthermore, because PG&E has no plans to alter current operations, PG&E concludes that impacts to State and Federally-listed threatened or endangered species from license renewal would be SMALL and do not warrant mitigation.

4.11 AIR QUALITY DURING REFURBISHMENT (NON-ATTAINMENT AREAS)

NRC

"…If the applicant's plant is located in or near a nonattainment or maintenance area, an assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce must be provided in accordance with the Clean Air Act as amended…." 10 CFR 51.53(c)(3)(ii)(F)

"…Air quality impacts from plant refurbishment associated with license renewal are expected to be small. However, vehicle exhaust emissions could be cause for concern at locations in or near nonattainment or maintenance areas. The significance of the potential impact cannot be determined without considering the compliance status of each site and the numbers of workers expected to be employed during the outage…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 50

The NRC made impacts to air quality during refurbishment a Category 2 issue because vehicle exhaust emissions could be cause for some concern, and a general conclusion about the significance of the potential impact could not be drawn without considering the compliance status at each site and the number of workers expected to be employed during an outage (Reference 18). Information needed would include: (1) the attainment status of the plant-site area, and (2) the number of additional vehicles as a result of refurbishment activities.

DCPP is located in a State non-attainment area for ozone (Refer to Section 2.10). The issue of air quality during refurbishment is not applicable to DCPP because, as discussed in Section 3.2, PG&E has no plans for refurbishment or other license renewal-related construction activities at DCPP. Further, since air emissions from the site, including emissions from testing emergency diesel generators, is regulated by a site-specific permit (Refer to Table 9-1) based on review of emissions in order to be protective of the State's air quality standards, impacts from continued operation are anticipated to be SMALL.

4.12 MICROBIOLOGICAL ORGANISMS

NRC

"If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river having an annual average flow rate of less than 3.15 × 10^{12}ft^3/year (9 × 10^{10}m^3/year), an assessment of the impact of the proposed action on public health from thermophilic organisms in the affected water must be provided." 10 CFR 51.53(c)(3)(ii)(G)

"…These organisms are not expected to be a problem at most operating plants except possibly at plants using cooling ponds, lakes, or canals that discharge to small rivers. Without site-specific data, it is not possible to predict the effects generically.…" 10 CFR 51, Subpart A, Table B-1, Issue 57

Due to the lack of sufficient data for facilities using cooling ponds, lakes, or canals that discharge to small rivers, the NRC designated impacts on public health from thermophilic organisms a Category 2 issue. Information to be ascertained is whether: (1) the plant uses a cooling pond, lake, or canal or discharges to a small river, and (2) discharge characteristics (particularly temperature) are favorable to the survival of thermophilic organisms.

This issue does not apply to DCPP because, as indicated in Section 3.1.2, DCPP does not use cooling ponds, lakes, or canals; and does not discharge to a small river. DCPP uses a once-through cooling system that withdraws water from and discharges water to the Pacific Ocean. The thermal discharge dissipates rapidly in the receiving water body, and conditions favorable to the survival of thermophilic organisms are not generated.

4.13 ELECTRIC SHOCK FROM TRANSMISSION-LINE-INDUCED CURRENTS

NRC

The environmental report must contain as assessment of the impact of the proposed action on the potential shock hazard from transmission lines "…[i]f the applicant's transmission lines that were constructed for the purpose of connecting the plant to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced currents." 10CFR 51.53(c)(3)(ii)(H)

"Electrical shocks resulting from direct access to energized conductors or from induced charges in metallic structures have not been found to be a problem at most operating plants and generally are not expected to be a problem during the license renewal term. However, site-specific review is required to determine the significance of the electric shock potential at the site." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 59

The NRC made impacts of electrical shock from transmission lines a Category 2 issue because, without a review of each plant's transmission line conformance with the National Electrical Safety Code (NESC, Part 2, Rules 232.C.1.c and 232.D.3.c) criteria, the NRC could not determine the significance of the electrical shock potential. In the case of DCPP, there have been no previous NRC or NEPA analyses of transmission-line-induced current hazards. Therefore, this section provides an analysis of the plant's transmission lines' conformance with the NESC standard. The analysis is based on computer modeling of induced current under the lines.

Objects near transmission lines can become electrically charged due to their immersion in the lines' electric field. This charge results in a current that flows through the object to the ground. The current is called "induced" because there is no direct connection between the line and the object. The induced current can also flow to the ground through the body of a person who touches the object. An object that is insulated from the ground can actually store an electrical charge, becoming what is called "capacitively charged." A person standing on the ground and touching a vehicle or a fence receives an electrical shock due to the sudden discharge of the capacitive charge through the person's body to the ground. After the initial discharge, a steady-state current can develop of which the magnitude depends on several factors, including the following:

- the strength of the electric field which, in turn, depends on the voltage of the transmission line as well as its height and geometry
- the size of the object on the ground
- the extent to which the object is grounded.

In 1977, the NESC adopted a provision recommending limiting the steady state current[2] due to electrostatic effects to 5 milliamperes (mA) for electric lines having voltages exceeding 98 kV alternating current (AC) to ground[3] root mean square (RMS). It was recommended that the field be limited so that the induced current due to electrostatic effects does not exceed 5 mA if the largest anticipated truck, vehicle, or equipment were short-circuited to ground. The rules allow this limit to be achieved by either increasing the vertical clearances of the line to the ground, or by reducing the electric field, or the electric field effects, by other means as required. The most common method of limiting the electric field is to increase the vertical clearance to ground.

It should be noted that the NESC is not the governing standard for the construction of overhead transmission lines in California. The governing standard is the State of California Public Utilities Commission's (CPUC) General Order 95, "Rules for Overhead Electric Line Construction". The three 500 kV lines and the double-circuit 230 kV line associated with DCPP were designed and constructed to comply with the applicable state rules. In addition, these transmission lines were constructed prior to 1977 and, therefore, pre-date the introduction of the NESC 5 mA rule. However, if the NESC regulations were to be applied to the PG&E transmission lines under consideration, the applicable NESC code would reflect the in-service date for these lines, and not the 2007 NESC requirements. Transmission lines built prior to 1977 would not have to be upgraded or altered in order to comply with this particular rule. Therefore, the present NESC 5 mA induced current rule is not applicable to these transmission lines.

As described in Section 3.1.7, there is one 230 kV double-circuit line that was constructed to supply offsite power to DCPP and three single-circuit 500 kV lines that were constructed to distribute power from DCPP to the electric grid. PG&E's analysis of these transmission lines began by identifying all road crossings and selecting the three lowest clearances for analysis for each line. These limiting cases are where the potential for current-induced shock would be greatest. Once the limiting case was identified for each transmission line, PG&E calculated the electric field strength for the line, then calculated the induced current.

PG&E calculated electric field strength under the lines using the Electric Power Research Institute (EPRI) computer code called ACDCLINE. The results of this computer program have been field-verified through actual electric field measurements by several utilities. The input parameters included the design features of the transmission line of interest and the NESC requirement that line sag be determined at 120°F conductor temperature. Next, PG&E calculated the induced current for the maximum vehicle size under the lines (a tractor-trailer), using methods prescribed in EPRI's Transmission Line Reference Book (Reference 5).

[2] The NESC and the GEIS use the phrase "steady-state current," whereas 10 CFR 51.53(c)(3)(ii)(H) uses the phrase "induced current." The phrases mean the same here.
[3] NESC Part 2, Rules 232C1c and 232D3c.

Table 4.13-1 provides the results of the induced current modeling. The analysis determined that there are no locations under the transmission line that have the capacity to induce more than 5 mA in a vehicle parked beneath the line (Reference 12).

PG&E's inspection and maintenance procedures provide assurance that design ground clearances will be maintained during continued operation of the line. These procedures include routine aerial patrols and detailed inspections. Routine aerial patrols of each transmission line are performed at least once each calendar year. The patrols are visual inspections of the transmission lines and include, but are not limited to, checks for rights-of-way (ROW) encroachments, inadequate conductor clearances, broken or flashed insulators, damaged or leaning structures, missing or bent tower members, and inadequate vegetation clearances. Any of these conditions might be evidence of a potential problem that could negatively impact compliance with the NESC's 5 mA rule.

In addition, PG&E conducts periodic detailed inspections of its transmission lines. A detailed inspection of each 500 kV transmission line is performed every 3 years. A detailed inspection of each 230 kV tower line is performed every 5 years. The detailed inspections are a close observation of the lines and their components that may be conducted by either ground or air. They are intended to ascertain if there are any abnormalities or circumstances that could negatively impact safety, reliability, or asset life. Detailed inspections include, but are not limited to, examination of proper vegetation clearance and the integrity of the structures and associated components.

Vegetation maintenance practices include routine tree trimming, clearing of vegetation from around the base of structures, and clearing of brush or trees adjacent to the transmission line or access road by using chippers, power saws, EPA-approved herbicides, mechanical equipment, or a combination of the above (Reference 17).

Since the DCPP transmission lines are in compliance with the recommendations of the 5 mA rule, PG&E's assessment under 10 CFR 51 concludes that electric shock is of SMALL significance for the DCPP transmission lines. Due to the small significance of the issue, mitigation measures, such as installing warning signs at road crossings or increasing clearances, are not warranted.

4.14 HOUSING IMPACTS

NRC

The environmental report must contain "...[a]n assessment of the impact of the proposed action on housing availability…" 10 CFR 51.53(c)(3)(ii)(I)

"…Housing impacts are expected to be of small significance at plants located in a medium or high population area and not in an area where growth control measures that limit housing development are in effect. Moderate or large housing impacts of the workforce associated with refurbishment may be associated with plants located in sparsely populated areas or areas with growth control measures that limit housing development…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 63

"...[S]mall impacts result when no discernible change in housing availability occurs, changes in rental rates and housing values are similar to those occurring statewide, and no housing construction or conversion occurs…." (NRC 1996, Section 4.7.1.1, pp. 4-101 to 4-102)

The NRC made housing impacts a Category 2 issue, because impact magnitude depends on local conditions which the NRC could not predict for all plants at the time of GEIS publication (Reference 18, Section 3.7.2). Local conditions that need to be ascertained are: (1) population categorization as small, medium, or high, and (2) applicability of growth control measures.

Refurbishment activities and continued operations could result in housing impacts as a result of increased staffing. As described in Section 3.2, PG&E has no plans to increase DCPP staff because no refurbishment-related activities required for extended operations have been identified. PG&E concludes that there would be no refurbishment-related impacts to area housing and no analysis is required. Accordingly, the following discussion focuses on impacts of continued DCPP operations on local housing availability.

As described in Section 2.6, DCPP is located in a medium population area. As noted in Section 2.8, the area of interest is not subject to growth control measures that limit housing development. In 10 CFR 51, Subpart A, Appendix B, Table B-1, the NRC concluded that impacts to housing are expected to be of small significance at plants located in a medium or high population area where growth control measures are not in effect. Therefore, PG&E expects housing impacts to be SMALL and would not warrant mitigation.

4.15 PUBLIC UTILITIES: PUBLIC WATER SUPPLY AVAILABILITY

NRC

The environmental report must contain "…an assessment of the impact of population increases attributable to the proposed project on the public water supply." 10 CFR 51.53(c)(3)(ii)(I)

"…An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 65

"Impacts on public utility services are considered small if little or no change occurs in the ability to respond to the level of demand and thus there is no need to add capital facilities. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs. Impacts are considered large if existing service levels (such as quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services." (NRC 1996)

The NRC made public utility impacts a Category 2 issue because an increased problem with water availability, resulting from pre-existing water shortages, could occur in conjunction with plant demand and plant-related population growth (Reference 18). Local information needed would include: (1) a description of water shortages experienced in the area and (2) an assessment of the public water supply system's available capacity.

The NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demands on local water resources. As Section 3.4 indicates, PG&E anticipates no increase in DCPP employment attributable to license renewal. Section 2.6 describes the DCPP regional demography. Section 2.9.1 describes the public water supply systems in the area, their permitted capacities, and current demands. As discussed in Section 3.2, no refurbishment is planned for DCPP and no refurbishment impacts are therefore expected.

DCPP does not use water from a municipal system and plant groundwater usage during the renewed license period of operation would be considered SMALL (Section 4.5); therefore, PG&E does not expect DCPP operation to have an effect on local water supplies.

Since PG&E has no plans to begin using municipal water for DCPP operation and since there are no plans to increase DCPP employment, PG&E concludes that impacts on the public water supply would be SMALL and would not require mitigation.

4.16 EDUCATION IMPACTS FROM REFURBISHMENT

NRC

The environmental report must contain "…[a]n assessment of the impact of the proposed action on…public schools (impacts from refurbishment activities only) within the vicinity of the plant…."
10 CFR 51.53(c)(3)(ii)(I)

"…Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors…." 10 CFR 51, Subpart A, Table B-1, Issue 66

"…[S]mall impacts are associated with project-related enrollment increases of 3 percent or less. Impacts are considered small if there is no change in the school systems' abilities to provide educational services and if no additional teaching staff or classroom space is needed. Moderate impacts are generally associated with 4 to 8 percent increases in enrollment. Impacts are considered moderate if a school system must increase its teaching staff or classroom space even slightly to preserve its pre-project level of service….Large impacts are associated with project-related enrollment increases above 8 percent…." (NRC 1996)

The NRC made refurbishment-related impacts to education a Category 2 issue because site-and project-specific factors determine the significance of impacts (Reference 18). Local factors to be ascertained include: (1) project-related enrollment increases and (2) status of the student/teacher ratio.

The issue of education impacts from refurbishment is not applicable to DCPP because, as discussed in Section 3.2, PG&E has no plans for refurbishment or other license-renewal-related construction activities at DCPP.

4.17 OFFSITE LAND USE

4.17.1 OFFSITE LAND USE - REFURBISHMENT

NRC

The environmental report must contain "…an assessment of the impact of the proposed action on... land-use... (impacts from refurbishment activities only) within the vicinity of the plant…" 10 CFR 51.53(c)(3)(ii)(I)

"…Impacts may be of moderate significance at plants in low population areas…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 68

"…[I]f plant-related population growth is less than 5 percent of the study area's total population, off-site land-use changes would be small, especially if the study area has established patterns of residential and commercial development, a population density of at least 60 persons per square mile, and at least one urban area with a population of 100,000 or more within 50 miles…." (NRC 1996)

The NRC made impacts to offsite land use as a result of refurbishment activities a Category 2 issue because land-use changes could be considered beneficial by some community members and adverse by others. Local conditions to be ascertained include: (1) plant-related population growth, (2) patterns of residential and commercial development, and (3) proximity to an urban area with a population of at least 100,000.

This issue is not applicable to DCPP because, as Section 3.2 discusses, PG&E has no plans for refurbishment as a result of license renewal at DCPP.

4.17.2 OFFSITE LAND USE – LICENSE RENEWAL TERM

NRC

The environmental report must contain "…an assessment of the impact of the proposed action on …land-use…within the vicinity of the plant…" 10 CFR 51.53(c)(3)(ii)(I)

"Significant changes in land use may be associated with population and tax revenue changes resulting from license renewal." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 69

"…[I]f plant-related population growth is less than five percent of the study area's total population, off-site land-use changes would be small…" (NRC 1996, Section 3.7.5)

"If the plant's tax payments are projected to be small, relative to the community's total revenue, new tax-driven land-use changes during the plant's license renewal term would be small, especially where the community has pre-established patterns of development and has provided adequate public services to support and guide development." (NRC 1996, Section 4.7.4.1)

The NRC made impacts to offsite land use during the license renewal term a Category 2 issue because land-use changes may be perceived as beneficial by some community members and adverse by others. Therefore, the NRC could not assess the potential significance of site-specific offsite land-use impacts (Reference 18, Section 4.7.4.1). Site-specific factors to be considered in an assessment of new tax-driven land-use impacts include: (1) the size of plant-related population growth compared to the area's total population, (2) the size of the plant's tax payments relative to the community's total revenue, (3) the nature of the community's existing land-use pattern, and (4) the extent to which the community already has public services in place to support and guide development.

The GEIS presents an analysis of offsite land use for the renewal term that is characterized by two components: population-driven and tax-driven impacts (Reference 18, Section 4.7.4.1).

4.17.2.1 Population-Related Impacts

As discussed in Section 2.6.1, from 1970 through 2000, the population increases in San Luis Obispo County and Santa Barbara County were relatively large. Only a small fraction of these increases could be attributed to construction and operation of DCPP. During the period of extended operation, PG&E has no plans to increase DCPP staff because no refurbishment-related activities required for extended operations have been identified.

Further, based on the GEIS case-study analysis, the NRC concluded that all new population-driven land-use changes during the license renewal term at all nuclear plants would be small. Population growth caused by license renewal would represent a much smaller percentage of the local area's total population than the percentage presented by operations-related growth (Reference 18, Section 4.7.4.2).

4.17.2.2 Tax-Revenue-Related Impacts

The NRC has determined that the significance of tax payments as a source of local government revenue would be large if the payments are greater than 20 percent of revenue, moderate if the payments are between 10 and 20 percent of revenue, and small if the payments are less than 10 percent of revenue (Reference 18, Section 3.7.3).

The NRC defined the magnitude of land-use changes as follows (Reference 18, Section 4.7.4):

SMALL – very little new development and minimal changes to an area's land-use pattern

MODERATE – considerable new development and some changes to an area's land-use pattern

LARGE – large-scale new development and major changes in land-use pattern

The NRC further determined that, if a plant's tax payments are projected to be small relative to the community's total revenue, new tax-driven land-use changes would be small, especially where the community has pre-established patterns of development and has provided adequate public services to support and guide development.

Table 2.7-1 provides a comparison of total tax payments made by PG&E to San Luis Obispo County's property tax revenues. For the 3-year period from 2004 through 2008, PG&E's tax payments to San Luis Obispo represented about 6 percent of the San Luis Obispo County's total annual property tax revenues. Using the NRC's criteria, PG&E's tax payments are of SMALL significance to San Luis Obispo County.

As stated in Section 2.6, San Luis Obispo County is a fast growing county in California (San Luis Obispo County 1980-2000 population growth of 59 percent compared to Calfornia State 1980-2000 population growth of 43 percent). San Luis Obispo County has a growing population and the region's economic base is increasingly diverse, with a variety of industries now supplementing traditional tourist-related businesses.

The surrounding population and the level of commercial and industrial activity in this region support the conclusion that DCPP has a small impact on the local economy and tax base. The local tax base is very large and tax payments made by PG&E are comparatively small.

PG&E does not anticipate refurbishment or license renewal-related construction during the license renewal period. Therefore, PG&E does not anticipate any increase in the assessed value of DCPP due to refurbishment-related improvements, or any related tax-increase-driven changes to offsite land-use and development patterns.

Any changes to the infrastructures of San Luis Obispo County would be attributable to the large population immigration already experienced by the County and a large pool of residential, industrial, and commercial tax payers.

4.17.2.3 Land Use and Public Services Impacts

San Luis Obispo County uses comprehensive land use plans and zoning and subdivision ordinances to guide development. These plans and ordinances have been in place for several decades. The ordinances promote open space preservation; protect agricultural land from urban sprawl; and provide a basis for orderly development. The ordinances require building permits, conditional use permits, minor use permits, plot and site plans, zoning clearances, and variance requests.

San Luis Obispo County has a pre-established pattern of development with controls for future development and has been able to provide the infrastructure needed to accommodate this growth. DCPP's presence is not expected to directly attract support industries and commercial development or to encourage or deter residential development. For these reasons, PG&E concludes that the land use impact would be SMALL. Mitigation for land-use impacts during the license renewal term would not be warranted.

4.18 TRANSPORTATION

NRC

The environmental report must "...assess the impact of highway traffic generated by the proposed project on the level of service of local highways during periods of license renewal refurbishment activities and during the term of the renewed license." 10 CFR 51.53(c)(3)(ii)(J)

"…Transportation impacts…are generally expected to be of small significance. However, the increase in traffic associated with additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites…." 10 CFR 51, Subpart A, Table B-1, Issue 70

Small impacts would be associated with U.S. Transportation Research Board Level of Service A, having the following condition: "…Free flow of the traffic stream; users are unaffected by the presence of others." And Level of Service B, having the following condition: "…Stable flow in which the freedom to select speed is unaffected but the freedom to maneuver is slightly diminished…." (NRC 1996)

The NRC made impacts to transportation a Category 2 issue because impacts are determined primarily by road conditions existing at the time of the project, which the NRC could not forecast for all facilities (Reference 18). Local road conditions to be ascertained are: (1) level of service conditions, and (2) incremental increase in traffic associated with refurbishment activities and license renewal staff.

As described in Section 3.2, no refurbishment is planned and no refurbishment impacts to local transportation are anticipated. Further evaluation for this impact is not applicable.

DCPP workforce currently includes approximately 1,350 employees. On a nominal 18-month cycle for each Unit, as many as 1,200 additional workers join the permanent workforce during a refueling outage, which typically lasts approximately 40 days. Given these employment projections and the average number of vehicles per day currently using the surrounding roads to DCPP (Table 2.9-1), PG&E concludes that impacts to transportation would be SMALL and mitigative measures would be unwarranted.

4.19 HISTORICAL AND ARCHAEOLOGICAL RESOURCES

NRC

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

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

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

The NRC made impacts to historic and archaeological resources a Category 2 issue, because determinations of impacts to historical and archaeological resources are site-specific in nature and the National Historic Preservation Act mandates that impacts must be determined through consultation with the State Historic Preservation Officer (Reference 18).

In DCPP's Final Environmental Statement, the AEC reported that the transmission lines proposed by PG&E would not produce an unreasonable burden on historic sites and buildings or archaeological sites (Reference 17). Additionally, a letter from the United States Department of the Interior stated that the site preparation and facility construction did not affect any existing or proposed sites of the National Park System, nor any site eligible for registration as National Historic, Natural or Environmental Education Landmarks (Reference 17). The FES and subsequent 1976 Addendum did not address the impact of station operation on historic and archaeological sites, however, in 1980, an Archeological Resources Management Plan was incorporated into the operating license for DCPP (Reference 6).

In November 2008, PG&E initiated consultation with the SHPO regarding the potential impact of continued operation of DCPP and its transmission lines (see Attachment D). The SHPO's response indicated that, due to the nature of the project, a Programmatic

Agreement should be executed to implement a Historic Properties Management Plan (HPMP) in moving forward with Section 106 consultation.

As discussed in Section 3.2, PG&E has no refurbishment plans and no refurbishment-related impacts are anticipated. Except for the detrimental effects that DCPP construction has on CA-SLO-2, PG&E is not aware of any other historic properties that have been affected to date by DCPP operations, including operation and maintenance of transmission lines. Currently, PG&E has no plans to construct additional facilities at DCPP related to license renewal. In addition, all other land-disturbing activities are completed in accordance with PG&E's corporate procedures (Reference 8) and the DCPP Archeological Resources Management Plan (Reference 11) to ensure the protection of cultural resources. Due to the protection measures in place, PG&E concludes that continued operation of DCPP over the license renewal term would result in SMALL impacts to cultural resources.

4.20 SEVERE ACCIDENT MITIGATION ALTERNATIVES

NRC

The environmental report must contain a consideration of alternatives to mitigate severe accidents "…if the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environment assessment..." 10 CFR 51.53(c)(3)(ii)(L)

"…The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 76

This section summarizes the PG&E analysis of alternative ways to mitigate the impacts of severe accidents. Attachment F provides a detailed description of the severe accident mitigation alternatives (SAMA) analysis.

The term "accident" refers to any unintentional event (i.e., outside the normal or expected plant operation envelope) that results in the release or a potential for release of radioactive material to the environment. NRC categorizes accidents as "design basis" or "severe." Design basis accidents are those for which the risk is great enough that NRC requires plant design and construction to prevent unacceptable accident consequences. Severe accidents are those that NRC considers too unlikely to warrant design controls.

NRC concluded in its license renewal rulemaking that the unmitigated environmental impacts from severe accidents met its Category 1 criteria. However, NRC made consideration of mitigation alternatives a Category 2 issue because not all plants had completed ongoing regulatory programs related to mitigation (e.g., individual plant examinations and accident management). Site-specific information to be presented in the license renewal environmental report includes: (1) potential SAMAs; (2) benefits, costs, and net value of implementing potential SAMAs; and (3) sensitivity of analysis to changes in key underlying assumptions.

PG&E maintains a probabilistic risk assessment (PRA) model to use in evaluating the most significant risks of radiological release from DCPP fuel assemblies and escape from the reactor coolant system into the containment structure.

For the SAMA analysis, PG&E used the PRA model output as input to an NRC-approved model that calculates economic costs and dose to the public from hypothesized releases from the containment structure into the environment

(Attachment F). Then, using NRC regulatory analysis techniques, PG&E calculated the monetary value of the unmitigated DCPP severe accident risk. The result represents the monetary value of the base risk of dose to the public and workers, offsite and onsite economic impacts, and replacement power. This value became a cost/benefit-screening tool for potential SAMAs; a SAMA whose cost of implementation exceeded the base risk value could be rejected as being not cost-beneficial.

DCPP used industry and DCPP-specific information to create a list of 25 SAMAs for consideration. PG&E analyzed this list and screened out SAMAs that would not apply to the DCPP design or that were deemed not cost beneficial based on their implementation costs and perceived dose benefits. PG&E prepared cost estimates for the remaining SAMAs and used the base risk value compared with estimated risk benefits via PRA modeling techniques to screen out SAMAs that would not be cost-beneficial.

PG&E calculated the risk reduction that would be attributable to each remaining candidate SAMA (assuming SAMA implementation) and re-quantified the risk value. The difference between the base risk value and the SAMA-reduced risk value became the averted risk, or the value of implementing the SAMA. PG&E used this information in conjunction with the cost estimates for implementing each SAMA to perform a detailed cost/benefit comparison.

PG&E performed additional analyses to evaluate how the SAMA analysis would change if certain key parameters were changed, including re-assessing the cost benefit calculations using the 95th percentile level of the failure probability distributions. The results of the uncertainty analysis are discussed in Attachment F, Section F.7.

Based on the results of this SAMA analysis, none of the SAMAs have a positive net value. However, when the 95th percentile probabilistic risk analysis results are considered, SAMAs 12, 13, 24, and 25 are potentially cost beneficial.

- SAMA 12: Improve Fire Barriers for auxiliary saltwater and component cooling water Equipment in the Cable Spreading Room
- SAMA 13: Improve Cable Wrap for the power operated relief valves in the Cable Spreading Room
- SAMA 24: Prevent Clearing of reactor coolant system Cold Leg Water Seals
- SAMA 25: Fill or Maintain Filled The Steam Generators to Scrub Fission Products

While these results are believed to accurately reflect potential areas for improvement at DCPP, PG&E notes that this analysis should not necessarily be considered a formal disposition of these proposed changes, as other engineering reviews are necessary to determine the ultimate resolution. PG&E will consider the four SAMAs using the appropriate DCPP design process. These SAMAs do not relate to the management of aging during the period of extended operation, and are therefore unrelated to any of the technical matters that must be addressed pursuant to 10 CFR 54.

4.21 ENVIRONMENTAL JUSTICE

From Regulatory Guide 4.2, Supplement 1

Environmental Justice was not reviewed in NUREG-1437. Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," issued on February 11, 1994, is designed to focus the attention of Federal agencies on the human health and environmental conditions in minority and low-income communities. The NRC Office of Nuclear Reactor Regulation (NRR) is guided in its consideration of environmental justice by Attachment 4, "NRR Procedures for Environmental Justice Reviews," to NRR Office Letter No. 906, Revision 2, "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues," September 21, 1999. NRR Office Letter No. 906 is revised periodically. The environmental justice review involves identifying off-site environmental impacts, their geographic locations, minority and low-income populations that may be affected, the significance of such effects and whether they are disproportionately high and adverse compared to the population at large within the geographic area, and if so, what mitigative measures are available, and which will be implemented. The NRC staff will perform the environmental justice review to determine whether there will be disproportionately high human health and environmental effects on minority and low-income populations and report the review in its SEIS. The staff's review will be based on information provided in the ER and developed during the staff's site-specific scoping process.

The consideration of environmental justice is required to assure that federal programs and activities will not have "disproportionately high and adverse human health or environmental effects…on minority populations and low income populations…." Section 2.6.2 notes minority and low-income groups within a 50-mile radius of this site.

As part of its environment assessment of this proposed action, PG&E has determined that the environmental impacts of renewing the DCPP license are SMALL. This conclusion is supported by the review of the Category 2 issues defined in 10 CFR 51.53(c)(3)(ii) presented in this ER.

No significant adverse impacts to the general population from the renewal of the DCPP license have been identified. Likewise, no unique disproportionately high or adverse impacts on minority or low-income populations would occur from the proposed action. Accordingly, no detailed review for environmental justice is necessary.

4.22 REFERENCES

1. Diablo Canyon Power Plant NPDES Permit, CA 0003751; Order No. 90-09, Central Coast Regional Water Quality Control Board, May 1990.

2. PG&E Diablo Canyon, Continuation of NPDES Permit No. CA0003751. Central Coast Regional Water Quality Control Board, Letter Dated June 26, 1995.

3. [“regulations (Title 23, Section 2235.4) allow your permit to remain valid until the new permit is issued”]. Central Coast Regional Water Quality Control Board, Letter Dated August 29, 1996.

4. Staff Testimony for Regular Meeting of July 10, 2003 Pacific Gas and Electric Company’s (PG&E’s) Diablo Canyon Power Plant Renewal of NPDES Permit. Central Coast Regional Water Quality Control Board, 2003.

5. Transmission Line Reference Book. 345 kV and Above. Third Edition, Revised. Electric Power Research Institute. Palo Alto, California. 2004.

6. Archaeological Resources Management Plan: Diablo Canyon Site, Greenwood, Roberta S., Pacific Gas and Electric Company, April 1980.

7. Diablo Canyon License Renewal Feasibility Study Environmental Report: Heat Shock Technical Data Report. Pacific Gas and Electric Company, San Francisco, CA. 2008.

8. Best Management Practices to Reduce Environmental Impacts. Revision 2. Pacific Gas and Electric Company. March 1, 2006.

9. Diablo Canyon License Renewal Feasibility Study Environmental Report: Impingement of Fish and Shellfish Technical Data Report. Pacific Gas and Electric Company, San Francisco, CA. 2009.

10. Diablo Canyon License Renewal Feasibility Study Environmental Report: Entrainment of Fish and Shellfish Technical Data Report. Pacific Gas & Electric Company, 2009.

11. DCPP Procedure EV1.ID2, CA-SLO-2 Site Management. Revision 3. Pacific Gas and Electric Company. May 14, 2008.

12. Diablo Canyon Power Plant Transmission Lines Induced Current Analyses. Prepared by Enercon Services, Inc. for Pacific Gas and Electric Company. 2009.

13. Diablo Canyon Power Plant Cooling Water Intake Structure 316(b) Demonstration. Tenera Inc. 1988.

14. Diablo Canyon Power Plant Thermal Effects Monitoring Program Analysis Report. Chapter 1. Changes in the marine environment resulting from the Diablo Canyon Power Plant thermal discharge. Prepared by Tenera Inc. for Pacific Gas and Electric Company, San Francisco, CA. 1997.

15. Diablo Canyon Power Plant 316(b) Demonstration Report. Tenera Inc. 2000.

16. Diablo Canyon Power Plant Receiving Water Monitoring Program: 1995 - 2002 Analysis Report. Prepared by Tenera Inc. for Pacific Gas and Electric Company, San Francisco, CA. 2002.

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

18. NUREG-1437: Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Volumes 1 and 2. U. S. Nuclear Regulatory Commission. Washington, D.C. May 1996.

19. Diablo Canyon Power Plant Cooling Tower Feasibility Study. Prepared by Enercon Services Inc. for Pacific Gas and Electric Company. March 2009.

TABLE 4.13-1

CALCULATED INDUCED CURRENTS

Road Crossing	Induced Current (mA)
Diablo-Gates 500 kV	
Cabrillo Highway (Hwy 1)	4.95
Estrella Road	3.40
Westside Freeway (5)	3.22
Diablo-Midway #2 500 kV	
Franco Western Road	3.07
Buttonwillow Drive	3.67
McKittrick Highway (58)	3.46
Diablo-Midway #3 500 kV	
Elk Grove Road	3.60
Buttonwillow Drive	3.36
McKittrick Highway (58)	3.22
Diablo-Mesa 230 kV/ Diablo-Gates #1 500 kV	
Los Osos Valley Road	3.25
Diablo-Midway #2 500 kV/ Diablo-Midway #3 500 kV	
El Camino Real (Hwy 101)	4.45
Price Canyon Road	4.25
West Ormonde Road	3.35

CHAPTER 5 – ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

NRC

"…The environmental report must contain any new and significant information regarding the environmental impacts of license renewal of which the applicant is aware." 10 CFR 51.53(c)(3)(iv)

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants and provides for license renewal. License renewal applications must include an environmental report (10 CFR 54.23) with the content as prescribed in 10 CFR 51. In an effort to streamline the environmental review, the NRC has resolved most of the environmental issues generically and only requires an applicant's analysis of the remaining issues.

While NRC regulations do not require an applicant's environmental report to contain analyses of the impacts of those environmental issues that have been generically resolved [10 CFR 51.53(c)(3)(i)], the regulations do require that an applicant identify any new and significant information of which the applicant is aware [10 CFR 51.53(c)(3)(iv)]. The purpose of this requirement is to alert the NRC staff to such information so the staff can determine whether to seek the Commission's approval to waive or suspend application of the rule with respect to the affected generic analysis. The NRC has explicitly indicated, however, that an applicant is not required to perform a site-specific validation of Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) conclusions (Reference 1).

New and significant information would include:

- Information that identifies a significant environmental issue not covered in the GEIS and codified in the regulation, or

- Information that was not covered in the GEIS analyses and that leads to an impact finding different from that codified in the regulation.

The NRC does not specifically define the term "significant". For the purpose of its review, PG&E used guidance available in Council on Environmental Quality (CEQ) regulations. CEQ guidance provides that federal agencies should prepare environmental impact statements for actions that would significantly affect the environment (40 CFR 1502.3), focus on significant environmental issues (40 CFR 1502.1), and eliminate from detailed study issues that are not significant [40 CFR 1501.7(a)(3)]. The CEQ guidance includes a lengthy definition of "significantly" that requires consideration of the context of the action and the intensity or severity of the impact(s) (40 CFR 1508.27). PG&E expects that moderate or large impacts, as defined by the NRC, would be significant. Chapter 4 presents the NRC definitions of “moderate” and “large” impacts.

The new and significant assessment process that PG&E used during preparation of the license renewal application included:

- Interviews with PG&E subject-matter experts on the validity of the conclusions in the GEIS as they relate to DCPP;
- A review of internal and external documents related to environmental issues at DCPP, including, but not limited to: environmental assessments and monitoring reports, procedures and other management controls, compliance history reports, and environmental resource plans and data;
- Correspondence with state and federal agencies to determine if the agencies had concerns not addressed in the GEIS;
- A review of other nuclear power plant license renewal applications for pertinent issues; and
- Credit for the oversight provided by inspections of plant facilities by state and federal regulatory agencies.

More specifically, PG&E environmental and license renewal personnel interviewed internal subject-matter experts, providing them with a written list of GEIS issue(s). The interviews focused on three general and five issue-specific questions in an effort to identify any new and potentially significant information, and participants were encouraged to identify any other information beyond that in the GEIS of which they may be aware. All responses were reviewed and documented with concurrence from each individual.

As a result of this assessment, PG&E is aware of no new and significant information regarding the environmental impacts of renewing DCPP’s operating licenses.

Several issues have been deemed new issues, but their impacts are not considered significant. These issues are: (1) groundwater monitoring for tritium, (2) long-term storage of low level radioactive waste, (3) the potential presence of a fault, 15 km in length, located approximately 1 km offshore, and (4) the September 11, 2001 terrorist attack.

TRITIUM GROUNDWATER MONITORING

Tritium groundwater sampling was initiated at DCPP in 2003 through the Radiological Environmental Monitoring Program (REMP). Groundwater sampling became an industry wide initiative in 2006. Results of this monitoring program are submitted to local, State, and Federal agencies on an annual basis.

DCPP Radiation Protection personnel undertook a review of the hydro-geological environment and the potential for a proximal receptor source for water borne pathways. As described in Sections 2.3 and 4.5, the only groundwater that is used for drinking water at the DCPP site is from Deep Well #2, located at a higher elevation (333.3 ft MSL) east of the power plant. Deep Well #2 draws from an isolated source specific to Diablo Canyon that is replenished by flows through the alluvium near 200 ft MSL (Section 2.3). The well is only a supplemental resource that is infrequently used. Freshwater production from the Seawater Reverse Osmosis (SWRO) Unit is the primary drinking water source. Potential releases of tritiated water from the operating power plant at 85 ft MSL cannot lead to any drinking water source due to overall site hydro-geological characteristics, and the higher elevation of the aquifer replenishing the location tapped by the deep water well. Thus, the DCPP Radiation Protection analysis concluded that DCPP site releases of tritiated water, should they occur, would not affect domestic water sources since there is no groundwater under the DCPP site that would lead to sources of offsite drinking water. There has been no detectable tritium in any possible sources of drinking water.

Furthermore, PG&E conducted studies of tritium contribution sources around the DCPP site from 2006-2008. Tritium was found to "wash-out" during rain events due to gaseous releases from the plant vents (direct rain collection and building downspouts). Tritium was found to concentrate into stagnant water due to diffusion in air from the plant vents and in condensation of air moisture in proximity to the plant vents.

In 2008, PG&E discovered tritium levels in excess of 400 pCi/L beneath the DCPP powerblock. The low levels and the location of the tritium found in groundwater at DCPP do not indicate a leak from the spent fuel pool or any other major source of tritium. Instead, the low levels are consistent with the minor tritium "wash-out" pathways discussed above.

Based on the above assessments and environmental staff evaluation, it was concluded that the potential for the communication of contaminated waters originating at the DCPP site with domestic water supplies regulated, owned, managed, or certified by State and Local governmental bodies does not exist. Therefore, impacts associated with tritium found in groundwater are determined to be SMALL and would not invalidate the NRC conclusions found in the DCPP FES or the GEIS.

LONG-TERM STORAGE OF LOW LEVEL RADIOACTIVE WASTE

PG&E's assessment process for potentially new and significant information regarding the environmental impacts of renewing the DCPP operating licenses identified a potential issue related to long-term storage of Low Level Radioactive Waste (LLW). Specifically, after June 30, 2008, LLW generators and licensees in 36 States, the District of Columbia, the Commonwealth of Puerto Rico, and the U.S. Territories no longer have access to the full-service LLW disposal facility in Barnwell, South Carolina. Consequently, many LLW generators must store a portion of their LLW for an indefinite period. This will include Class B and C waste as well as certain Class A waste streams that do not meet the waste acceptance criteria of the LLW disposal facility in Clive, Utah.

The Commission also concluded in Section 6.4.4.6 of the GEIS (Reference 2) "that there is reasonable assurance that sufficient LLW disposal capacity will be made available when needed for facilities to be decommissioned consistent with NRC decommissioning requirements" and that "LLW storage and disposal will have small environmental impacts." Consequently, LLW storage and disposal is a Category 1 issue.

Based on the review of the discussion of the environmental impacts of LLW storage and disposal in the GEIS, PG&E concludes that the closure of Barnwell to out-of-compact waste is not new and significant information that warrants further discussion in this report. The environmental impacts of extended on-site storage are addressed in the GEIS.

POTENTIAL FAULT

On November 14, 2008, PG&E notified the NRC that preliminary results from ongoing studies by PG&E and the U.S. Geological Survey (USGS) indicate that there is a zone of seismicity that could indicate the presence of a fault approximately 15 km in length, located approximately 1 km offshore from DCPP. Subsequently, PG&E has informally referred to this zone of seismicity as the potential "Shoreline Fault." PG&E has been collaborating with the USGS to collect and analyze new geological, geophysical, and seismic data to develop improved tectonic models for the central California coastal region through the Collaborative Research and Development Agreement.

PG&E informed the NRC staff that it had performed an initial evaluation of the potential ground motion levels at DCPP from the hypothesized fault which concluded that these motions would be bounded by the ground motion levels previously determined for the current licensing basis (the larger Hosgri fault). In addition, PG&E stated that the tsunami hazard threat is relatively small since it is a strike-slip fault rather than a reverse fault and, therefore, the tsunami hazard from the potential new fault is not expected to exceed the plant's design basis tsunami hazard levels.

The NRC staff undertook a preliminary independent review of possible implications of the potential Shoreline Fault to DCPP using the initial information provided by USGS through PG&E. This review is documented in Research Information Letter RIL 09-001, "Preliminary Deterministic Analysis of Seismic Hazard at Diablo Canyon Nuclear Power Plant from Newly Identified 'Shoreline Fault'," and can be found in Agencywide Documents Access and Management System (ADAMS) Accession No. ML090330523 (Reference 3).

The NRC staff's assessment indicates that the best estimate 84th percentile deterministic seismic-loading levels predicted for a maximum magnitude earthquake on the potential Shoreline Fault are below those levels for which the plant was previously analyzed in the DCPP Long-Term Seismic Program. Considering the results of the deterministic analyses as a whole and the current level of uncertainty, the NRC staff concludes that the postulated Shoreline Fault will not likely cause ground motions that exceed those for which DCPP has already been analyzed. The NRC staff also concludes that the potential Shoreline Fault has a dominant strike-slip faulting mechanism. It is highly unusual for strike-slip faulting to cause the type of significant seafloor elevation change necessary to cause a sizable tsunami and so the NRC staff would not expect any significant changes in the tsunami hazard assessment.

Although the presence of the potential Shoreline Fault offshore of DCPP is new information, based on the PG&E and NRC assessments of the potential Shoreline Fault, it is not significant information since the design and licensing basis evaluations of the DCPP structures, systems, and components are not expected to be adversely affected.

TERRORISM

The NRC has evaluated whether the environmental impacts of the September 11, 2001 terrorist act need to be considered under NEPA as part of the renewed operating license review. The NRC has concluded, for license renewal applications, that terrorist attacks are too far removed from natural or expected consequences of NRC action to require an environmental impact analysis (Reference 4). Moreover, the NRC has nonetheless already included a sabotage/terrorism assessment in the license renewal GEIS, Chapter 5 (Reference 2). The NRC concludes (at 5-18) that "the regulatory requirements under 10 CFR part 73 provide reasonable assurance that the risk from sabotage is small. Although the threat of sabotage events cannot be accurately quantified, the commission believes that acts of sabotage are not reasonably expected. Nonetheless, if such events were to occur, the Commission would expect that the resultant core damage and radiological releases would be no worse that those expected from internally initiated events."

Given the inherent inability to quantify the probability of hypothetical aircraft impacts and other terrorist-initiated events, and the NRC's previous conclusion that impacts initiated by a terrorist attack can be correlated to the generic assessment of other internally initiated severe accidents, intentional aircraft impacts and other terrorist-initiated events are not considered further in the DCPP environmental analysis (see Attachment F). To the extent necessary, the NRC can address this issue further based on information available in agency records.

5.1 REFERENCES

1. NUREG-1529: Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response. U.S. Nuclear Regulatory Commission. Office of Nuclear Regulatory Research, Washington, D.C. May 1996.

2. NUREG-1437: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS), Volumes 1 and 2. U.S. Nuclear Regulatory Commission. Washington, D.C. May 1996.

3. Research Information Letter RIL 09-001. Preliminary Deterministic Analysis of Seismic Hazard at Diablo Canyon Nuclear Power Plant from Newly Identified 'Shoreline Fault'. U.S. Nuclear Regulatory Commission. 2009. Available at Agencywide Documents Access and Management System (ADAMS) Accession No. ML090330523.

4. New Jersey Department of Environmental Protection v. U.S. Nuclear Regulatory Commission & Amergen Energy Company. U.S. Court of Appeals for the Third Circuit. Case 07-2271, Document 00318362723, Date Filed: 03/31/2009.

CHAPTER 6 – SUMMARY OF LICENSE RENEWAL IMPACTS & MITIGATING ACTIONS

6.1 LICENSE RENEWAL IMPACTS

PG&E has reviewed the environmental impacts of renewing the DCPP operating licenses and has concluded that all impacts would be SMALL and would not require additional mitigation. This environmental report documents the basis for PG&E's conclusion. Chapter 4 incorporates by reference the NRC findings for the 52 Category 1 issues that apply to DCPP, all of which have impacts that are SMALL (Attachment A, Table A-1). Chapter 4 also analyzes Category 2 issues, all of which are either not applicable or have impacts that would be SMALL. Table 6-1 identifies the impacts that DCPP license renewal would have on resources associated with Category 2 issues.

6.2 MITIGATION

NRC

> "The report must contain a consideration of alternatives for reducing adverse impacts…for all Category 2 license renewal issues…" 10 CFR 51.53(c)(3)(iii)
>
> "The environmental report shall include an analysis that considers and balances…alternatives available for reducing or avoiding adverse environmental effects…" 10 CFR 51.45(c) as incorporated by 10 CFR 51.53(c)(2) and 10 CFR 51.45(c)

Impacts of license renewal are SMALL and would not require mitigation. Current operations include monitoring activities that would likely continue during the license renewal term. PG&E performs routine mitigation and monitoring in accordance with the current operating license requirements (DPR-80 and DPR-82, Appendix B) to ensure the safety of workers, the public, and the environment. These activities include, but are not limited to:

- Biological Monitoring (Proximal Marine and Terrestrial Environments)
- Radiological Environmental Monitoring Program
- Once-Through Cooling System Influent and Effluent Monitoring
- Receiving Water Monitoring Program (Thermal Discharge Impacts Assessment)
- Plant Systems Waste Water Discharge Quality Monitoring
- Diesel Fuel Oil Use and Combustion Emissions Monitoring

Results of these monitoring programs are submitted to local, state, and federal agencies on a periodic basis. Additionally, the NRC periodically performs inspections and evaluates the effectiveness of the programs. Recent NRC inspection report findings (IR 2004-009; IR 2006-013) have not identified any findings of significance.

The monitoring programs ensure that the plant's permitted emissions and discharges are within regulatory limits and any unusual or off-normal emissions/discharges would be quickly detected, mitigating potential impacts. Therefore, this environmental report finds that no additional mitigation measures are sufficiently beneficial as to be warranted.

6.3 UNAVOIDABLE ADVERSE IMPACTS

NRC

The environmental report shall discuss "Any adverse environmental effects which cannot be avoided should the proposal be implemented;" 10 CFR 51.45(b)(2) as adopted by 10 CFR 51.53(c)(2)

This environmental report adopts by reference the NRC findings for applicable Category 1 issues, including discussions of any unavoidable adverse impacts (Attachment A, Table A-1). PG&E examined 21 Category 2 issues and identified the following unavoidable adverse impacts of license renewal.

- Water for cooling would continue to be withdrawn from the Pacific Ocean.
- Waste heat from operation of DCPP would continue to be discharged to the Pacific Ocean.
- Small numbers of juvenile and adult fish, and some shellfish, would continue to be impinged on the intake traveling screens.
- Sea turtles may occasionally be impinged on the intake structures. DCPP has mitigation measures in place to minimize adverse impacts.
- A small percentage of larval fish and shellfish in the cooling system source water would continue to be entrained at the intake structure.
- Operation of DCPP would result in a very small increase in radioactivity in the air and Pacific Ocean. However, fluctuations in natural background radiation would be expected to exceed the small incremental increase in dose to the local population. Operation of DCPP also would create a very low probability of accidental radiation exposure to inhabitants of the area.
- Procedures for the disposal of sanitary, chemical, and radioactive wastes are intended to reduce adverse impacts from these sources to acceptably low levels. Solid radioactive wastes are a product of plant operations and long-term disposal of these materials will be required.

Based on the discussion and analyses presented in Chapter 4, PG&E expects that all unavoidable adverse impacts resulting from renewal of the DCPP operating licenses would be SMALL.

6.4 IRREVERSIBLE AND IRRETRIEVABLE RESOURCE COMMITMENTS

NRC

The environmental report shall discuss "Any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented." 10 CFR 51.45(b)(5) as adopted by 10 CFR 51.53(c)(2)

The continued operation of DCPP for the period of extended operation will result in irreversible and irretrievable resource commitments, including the following:

- Nuclear fuel, which is consumed in the reactor and converted to radioactive waste.

- The land required to store, or dispose of low-level radioactive wastes generated as a result of plant operations, and solid and sanitary wastes generated from normal industrial operations.

- PG&E's preferred approach for additional spent fuel storage is to either ship the spent fuel to a Federal waste repository or waste reprocessing facility. In the Agency's 1990 Waste Confidence findings, the NRC previously assessed its degree of confidence that radioactive wastes produced by nuclear power plants could be safely disposed of, and made 5 findings (55 FR 38474, September 18, 1990). These 5 findings form the basis of the NRC's generic determination of no significant environmental impact from temporary storage of spent nuclear fuel. In 1999, the NRC confirmed these findings (64 FR 68005, December 6, 1999). In 2008, the NRC proposed updated Waste Confidence findings (FR 59551, dated October 9, 2008), including findings that there is reasonable assurance a sufficient mined geologic repository can reasonably be expected to be available within 50-60 years beyond the licensed life for operation of any reactor to dispose of the commercial high-level waste and spent fuel. The NRC further concluded there is reasonable assurance that, if necessary, spent fuel generated in any reactor can be stored safely without significant environmental impacts for at least 60 years beyond the licensed life for operation (which may include the term of a revised or renewed license) of that reactor in a combination of storage in its spent fuel storage basin and either onsite or offsite independent spent fuel storage installations.

- Elemental materials that will become radioactive.

- Materials used for the normal industrial operations of the plant that cannot be recovered or recycled or that are consumed or reduced to unrecoverable forms.

PG&E has not identified any activities during the license renewal term that would irreversibly or irretrievably commit additional resources beyond those committed during the construction and operation of DCPP during the initial operating license terms, and the preemption of land and consumption of materials such as those discussed above. Consistent with conclusions of the AEC with regard to operations in the current license terms (Reference 1), PG&E concludes that these resource commitments are appropriate for the benefits gained by license renewal and extended DCPP operation.

6.5 SHORT TERM USE VERSUS LONG-TERM PRODUCTIVITY OF THE ENVIRONMENT

NRC

The environmental report shall discuss "The relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity..." 10 CFR 51.45(b)(4) as adopted by 10 CFR 51.53(c)(2)

The current balance between short-term use and long-term productivity at DCPP was established when the Final Environmental Statements was issued in 1973 (Reference 1). The DCPP Final Environmental Statement evaluated the impacts of constructing and operating DCPP in Avila Beach, California. Approximately 750 acres were acquired for the plant and buffer areas, in addition to that needed for transmission line corridors. The major impact was loss of land for grazing cattle.

After decommissioning, many environmental disturbances would cease and some restoration of the natural habitat would occur. Thus, the "trade-off" between the production of electricity and changes in the local environment is reversible to some extent.

Experience with other experimental, developmental, and commercial nuclear plants has demonstrated the feasibility of decommissioning and dismantling such plants sufficiently to restore a site to its former use. The degree of dismantlement, will take into account the intended new use of the site and a balance among health and safety considerations, salvage values, and environmental impact. However, decisions on the ultimate disposition of these lands have not yet been made. Continued operation for an additional 20 years would not alter this conclusion.

PG&E notes that the current balance between short-term use and long-term productivity at DCPP is now well established and can be expected to remain essentially unchanged by the renewal of the operating licenses and extended operation of DCPP. Extended operation would postpone restoration of the site and its potential availability for other uses. It would also result in other short-term impacts on the environment, all of which have been determined to be SMALL on the basis of the NRC's evaluation in the GEIS and PG&E's evaluation in this environmental report.

6.6 REFERENCES

1. Final Environmental Statement related to the Nuclear Generating Station Diablo Canyon Units 1 and 2, Docket Numbers 50-275 and 50-323, Pacific Gas and Electric Company. U.S. Atomic Energy Commission. 1973.

TABLE 6-1 Sheet 1 of 3

CATEGORY 2 ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL AT DCPP

Issue	Environmental Impact
Surface Water Quality, Hydrology, and Use (for all plants)	
13. Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	**NONE.** This issue does not apply because DCPP does not use cooling ponds or cooling towers that withdraw makeup water from a small river with no flow.
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)	
25. Entrainment of fish and shellfish in early life stages (for plants with once-through and cooling pond heat dissipations systems)	**SMALL.** PG&E has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements.
26. Impingement of fish and shellfish in early life stages (for plants with once-through and cooling pond heat dissipations systems)	**SMALL.** PG&E has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements.
27. Heat shock (for plants with once-through and cooling pond heat dissipations systems)	**SMALL.** PG&E has a current NPDES permit which constitutes compliance with CWA Section 316(a) requirements.
Groundwater Use and Quality	
33. Groundwater use conflicts (potable, service water, and dewatering; plants that use >100 gpm)	**SMALL.** DCPP does not withdraw groundwater at an average rate greater than 100 gpm.
34. Groundwater use conflicts (plants using cooling towers withdrawing makeup water from a small river)	**NONE.** This issue does not apply because DCPP does not use cooling towers that withdraw makeup water from a small river.
35. Groundwater use conflicts (Ranney wells)	**NONE.** This issue does not apply because DCPP no longer uses Ranney wells.
39. Groundwater quality degradation (cooing ponds at inland sites)	**NONE.** This issue does not apply because DCPP is not located at an inland site and does not use cooling ponds.
Terrestrial Resources	
40. Refurbishment impacts to terrestrial resources	**NONE.** No impacts are expected because PG&E has no plans to undertake refurbishment because of license renewal.
Threatened or Endangered Species (for all plants)	
49. Threatened or endangered species	**SMALL.** No effects on any state or federally-listed or other special status plant or animal species, including designated critical habitat, are anticipated as a result of extending the operating license. PG&E does not plan to alter current

TABLE 6-1 Sheet 2 of 3

Issue	Environmental Impact
	operations over the license renewal period.
Air Quality	
50. Air quality during refurbishment (non-attainment and maintenance areas)	**NONE.** No impacts are expected because PG&E will not undertake refurbishment because of license renewal.
Human Health	
57. Microbiological organisms (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	**NONE.** This issue does not apply because DCPP does not use cooling ponds, lakes, canals, or small rivers.
59. Electromagnetic fields, acute effects	**SMALL**. The largest modeled induced current under the DCPP lines is less than the 5-mA limit. Therefore, the DCPP transmission lines conform to the National Electrical Safety Code provisions for preventing electric shock from induced current.
Socioeconomics	
63. Housing impacts	**SMALL.** For the purpose of license renewal, PG&E does not plan on any refurbishment and does not plan to add employees. Therefore, there will be no increased demand on housing because of license renewal.
65. Public services: public utilities	**SMALL.** For the purpose of license renewal, PG&E does not plan on any refurbishment and does not plan to add employees. Therefore, there will be no increased demand on public utilities because of license renewal.
66. Public services: education (refurbishment)	**NONE.** No impacts are expected because PG&E will not undertake refurbishment because of license renewal.
68. Offsite land use (refurbishment)	**NONE.** No impacts are expected because PG&E will not undertake refurbishment because of license renewal.
69. Offsite land use (license renewal term)	**SMALL.** Although taxes paid by the plant constitute a large fraction of the county revenue, the county has not shown significant offsite land use change since DCPP construction. No plant-induced changes to offsite land use are expected from license renewal. Therefore, continued operation is expected to have positive impacts.
70. Public services: transportation	**SMALL.** For the purpose of license renewal, PG&E does not plan on any refurbishment and does not plan to add employees. Therefore,

TABLE 6-1 Sheet 3 of 3

Issue	Environmental Impact
	there will be no increased demand on local transportation because of license renewal.
71. Historic and archaeological resources	**SMALL.** PG&E does not plan on any refurbishment or transmission-line corridor changes because of license renewal. Continued plant site operations are not expected to impact cultural resources.
Postulated Accidents	
76. Severe accidents	**SMALL.** The benefit/cost analysis did not identify any cost-effective aging-related severe accident mitigation alternatives.

CHAPTER 7 - ALTERNATIVES TO THE PROPOSED ACTION

NRC

> The environmental report shall discuss "Alternatives to the proposed action.…" 10 CFR 51.45(b)(3), as adopted by reference at 10 CFR 51.53(c)(2)
>
> "...The report is not required to include discussion of need for power or economic costs and benefits of ... alternatives to the proposed action except insofar as such costs and benefits are either essential for a determination regarding the inclusion of an alternative in the range of alternatives considered or relevant to mitigation...."
> 10 CFR 51.53(c)(2)
>
> "While many methods are available for generating electricity, and a huge number of combinations or mixes can be assimilated to meet a defined generating requirement, such expansive consideration would be too unwieldy to perform given the purposes of this analysis. Therefore, NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable…" (NRC 1996)
>
> "…The consideration of alternative energy sources in individual license renewal reviews will consider those alternatives that are reasonable for the region, including power purchases from outside the applicant's service area...." (NRC 1996)

Chapter 7 evaluates alternatives to Diablo Canyon Power Plant (DCPP) license renewal. In this chapter, Pacific Gas and Electric Company (PG&E) identifies reasonable alternatives to renewal of the operating licenses for DCPP Units 1 and 2, and describes the environmental impacts of these reasonable alternatives. This chapter also includes descriptions of alternatives that were considered by PG&E, but determined to be unreasonable, as well as the supporting rationale for those determinations.

PG&E divided its alternatives discussion into two categories: "no-action" and "alternatives that meet system generating needs." In considering the level of detail and analysis that it should provide for each category, PG&E relied on the NRC decision-making standard for license renewal:

> "…the NRC staff, adjudicatory officers, and Commission shall determine whether or not the adverse environmental impacts of license renewal are

> so great that preserving the option of license renewal for energy planning decision makers would be unreasonable." [10 CFR 51.95(c)(4)]

The environmental impact evaluations of alternatives presented in this chapter are not intended to be exhaustive. Rather, PG&E generally structured the analysis to focus on comparative impacts, specifically whether an alternative's impacts would be greater, smaller, or similar to the proposed action.

Providing additional detail or analysis was not considered beneficial or necessary if it only brings to light additional adverse impacts of alternatives to license renewal. This approach is consistent with regulations of the Council on Environmental Quality, which provide that the consideration of alternatives (including the proposed action) should enable reviewers to evaluate their comparative merits (40 CFR 1500-1508). This chapter establishes the basis for necessary comparisons to the Chapter 4 discussion of impacts from the proposed action.

In characterizing environmental impacts from alternatives, PG&E has used the same definitions of "small," "moderate," and "large" that are presented in the introduction to Chapter 4 and used by the NRC in its Generic Environmental Impact Statement (GEIS) (Reference 21).

7.1 NO-ACTION ALTERNATIVE

PG&E uses “no-action alternative” to refer to a scenario in which the NRC does not renew the DCPP operating licenses for Units 1 and 2. Under the no-action alternative, operation of Units 1 and 2 would cease upon expiration of the current operating licenses in 2024 and 2025. Components of this alternative include decommissioning the facility and replacing the generating capacity of DCPP.

DCPP provides approximately 2,285 megawatts (Reference 4) of baseload, low carbon electricity to PG&E’s customers. Because Units 1 and 2 constitute a significant block of long-term baseload capacity, it is reasonable to assume that a decision not to renew the operating licenses for both Units would necessitate the replacement of its approximately 2,285 MWe capacity with other sources of generation. Replacement could be accomplished by (1) building new generating capacity, (2) purchasing power from the wholesale market, or (3) reducing power requirements through demand reduction. Section 7.2.1 identifies and describes alternative generating technologies as potential candidate technologies to replace the DCPP baseload capacity. PG&E considered any alternative that could not replace the capacity of DCPP an unreasonable alternative. Conversely, if an alternative technology could replace the capacity of DCPP, PG&E considered that a reasonable alternative. Section 7.2.2 describes environmental impacts of reasonable alternatives, including purchased power. In addition, with respect to demand reduction, PG&E will need to pursue all feasible energy efficiency and renewable energy options in order to meet California’s aggressive renewable power requirements and Greenhouse Gas Emissions Performance Standards. It is unlikely that there will be enough renewable generation or demand reduction to both meet these requirements and also replace 2,285 MW of DCPP baseload generation with renewable power or energy efficiency. Therefore, the "no action" alternative could undermine efforts to meet those standards.

Under the no-action alternative, PG&E would continue operating DCPP until the existing licenses expire, then initiate decommissioning activities in accordance with NRC requirements. The Generic Environmental Impact Statement (GEIS) (Reference 21) defines decommissioning as the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license. NRC-evaluated decommissioning options include immediate decontamination and dismantlement (DECON option) and safe storage of the stabilized and defueled facility for a period of time, followed by additional decontamination and dismantlement (SAFSTOR option). Regardless of the option chosen, decommissioning must be completed within a 60-year period after expiration of the operating licenses. The GEIS describes decommissioning activities based on an evaluation of the “reference” pressurized-water reactor (the 1,175-megawatt-electric [MWe] Trojan Nuclear Plant). This description is applicable to decommissioning activities that PG&E would conduct at DCPP.

As the GEIS notes, NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts include impacts of occupational and public radiation dose;

impacts of waste management; impacts to air and water quality; and ecological, economic, and socioeconomic impacts. NRC indicated in the “Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities; Supplement 1” (Reference 23) that the environmental effects of greatest concern (i.e., radiation dose and releases to the environment) are substantially less than the same effects resulting from reactor operations. PG&E adopts by reference the NRC conclusions regarding environmental impacts of decommissioning.

PG&E notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. PG&E will have to decommission DCPP regardless of the NRC decision on license renewal; license renewal would only postpone decommissioning for another 20 years. NRC has established in the GEIS that the timing of decommissioning operations does not substantially influence the environmental impacts of decommissioning. PG&E adopts by reference the NRC findings (10 CFR 51, Appendix B, Table B-1, Decommissioning) to the effect that delaying decommissioning until after the renewal term would have small environmental impacts.

PG&E also notes that the no-action alternative could have an impact on area real estate values following DCPP shutdown and decommissioning. PG&E employs approximately 1,350 employees at DCPP and more than 95 percent of these employees reside in San Luis Obispo and Santa Barbara Counties. Since DCPP is noted to be one of the largest employers in San Luis Obispo County (Reference 16), the reduction in overall long-term site workforce (1) could force employees to relocate to another area with similar job-types available, (2) could result in a lower median County income, and (3) could thus, impact area real estate values.

PG&E concludes that the decommissioning impacts would not be substantially different from those occurring following license renewal, as identified in the GEIS (Reference 21) and in the decommissioning generic environmental impact statement (Reference 23). These impacts would be temporary and would occur at the same time as the impacts from meeting system generating needs.

The discriminators between the proposed action and the no-action alternative are to be found within the choice of generation replacement options. Section 7.2.2 analyzes the environmental impacts from these options.

7.2 ALTERNATIVES

DCPP has a net capacity of 2,285 MWe and in 2007 generated approximately 18.6 terawatt-hours of electricity (Reference 17). If the DCPP operating licenses were not renewed, the power produced by DCPP, which represents a significant portion of the energy that PG&E supplies to customers in its service territory, would not be available. PG&E would need to build new generating capacity, purchase power, or reduce power requirements through demand reduction to meet the electric power requirements of its customers.

The current mix of power generation options in California is one indicator of what PG&E considers to be feasible alternatives. In 2007, electric generators in California had a gross power output of 210,847 Gigawatt Hours (GWh). This capacity includes units fueled by natural gas (60.4 percent), hydroelectric (15.7 percent), other renewables (9.0 percent), nuclear (6.9 percent), pumped storage (5.8 percent), petroleum (1.2 percent), coal (0.6 percent), and other gases (0.4 percent). Actual utilization of energy consists of natural gas (54.9 percent), hydroelectric (13 percent), nuclear (17 percent), other renewables (11.8 percent), petroleum (1.1 percent), coal (1.1 percent), other gases (0.9 percent), and pumped storage (0.1 percent). Figures 7.2-1 and 7.2-2 show California's electric generating capacity and actual utilization (Reference 19).

Comparison of actual utilization of generation capacity in California indicates that nuclear, natural gas, and hydroelectric are used by electric generators in the State more than other methods of generation. This condition reflects the relatively low fuel cost for nuclear, natural gas, and hydroelectric power plants for baseload, and the relatively higher use of oil and gas-fired units to meet peak loads. In addition, the utilization reflects the availability of nuclear and hydroelectric power relative to other sources with intermittent availability (e.g., renewables).

In 2008, California reserve margins were approximately 22 percent (Reference 8). The California Energy Commission defines planning reserve margin as the minimum level of electricity supplies needed to cover a range of unexpected contingencies, such as increased air conditioning demand on a hotter than average day, or an unplanned maintenance outage at a power plant. California energy demand is projected to increase from 277,479 GWh in 2008 to 313,671 GWh in 2018 (Reference 5, Form 1.1b). Of these statewide energy demand projections, PG&E would comprise approximately 37 percent of the energy (Reference 5, Form 1.1c).

7.2.1 ALTERNATIVES CONSIDERED

For purposes of this environmental report, PG&E conducted evaluations of alternative generating technologies to identify candidate technologies that would be capable of replacing the net baseload capacity of the two nuclear units at DCPP. Alternatives considered included the following:

- natural gas

- purchased power
- demand side management
- nuclear
- coal
- oil
- wind
- solar thermal
- photovoltaics
- hydropower
- geothermal
- wood energy
- municipal solid waste
- other biomass-derived fuels
- fuel cells
- delayed retirement

Based on these evaluations, PG&E determined that the only viable alternative generation technology to replace DCPP power is natural gas-fired generation. California laws and regulations preclude building and operating new nuclear, coal and oil-fired power plants in California. Additionally, California's aggressive renewable power and energy efficiency requirements require PG&E to pursue all available and technologically feasible renewable power and energy efficiency; it is unlikely that there will be enough renewable generation or demand reduction to both meet these requirements and also replace 2,285 MW of DCPP baseload generation with renewable power or energy efficiency. Moreover, it would be imprudent to forego the opportunity to continue operating DCPP after 2025 based on an assumption that renewable technology and energy efficiency will have advanced sufficiently and be available to replace 2,285 MW of DCPP baseload generation.

Finally, overlaying these concerns about the alternative generation technologies are federal and state greenhouse gas emissions reduction goals. According to EPRI, even while adding renewable capacity equal to 4 times today's wind and solar capacity, the United States must maintain all of its current nuclear capacity, and add 45 more nuclear facilities, to meet greenhouse gas emissions reduction goals.

Mixture

The NRC indicated in the GEIS that, while many methods are available for generating electricity and numerous combinations or mixes can be assimilated to meet system needs, it would be impractical to analyze all the combinations. Therefore, NRC determined that the alternatives evaluation should be limited to analysis of single discrete electrical generation sources and only those electric generation technologies that are technically feasible and commercially viable (Reference 21).

7.2.1.1 Alternatives that Meet System Generating Needs

Natural-Gas-Fired Generation

Natural gas provides the fuel for most new power generation facilities in the State. Lawrence Berkeley National Laboratory estimated that the demand for natural gas-fired generation could drop about 1 percent per year from 2011 to 2020, reaching about 9 percent below 2010 levels (Reference 10).

As described in PG&E's January 2004 Proponent's Environmental Assessment (Reference 25), PG&E would need to design, permit, and construct several combined-cycle gas turbine power plants somewhere in California, most-likely in the southern Central Valley region, to replace the output of DCPP. If DCPP output were replaced exclusively with combined-cycle gas turbine power plants, four plants would need to be constructed (2,250 MW at 562.5 MW per plant). These combined-cycle gas turbine power plants are typically configured in a two-on-one design (two gas turbines and one steam turbine with associated heat recovery steam generators and duct burners). Considering auxiliary power requirements for the plant, the nominal net capacity output for General Electric Frame 7F Technology combustion turbines would be 562.5 MW. The capital cost for constructing this hypothetical 562.5 MW power plant is assumed to be approximately $725 to $850 million[1].

Purchased Power

"Purchased power" is power purchased and transmitted from electric generation plants that the applicant does not own and that are located elsewhere within the region, nation, Canada, or Mexico. If available, purchased power from other sources could potentially obviate the need to renew the DCPP license.

Purchased power is a feasible alternative to DCPP license renewal. There is no assurance, however, that sufficient capacity or energy would be available during the entire time frame of 2025 through 2045 to replace the approximately 2,285 MWe of baseload generation. This is supported by the Energy Information Administration (EIA) projection that total gross U.S. imports of electricity will increase from 28.7 quadrillion Btu in 2008 to 31.45 quadrillion Btu in the year 2030 (Reference 18). It appears unlikely that electricity imported from Canada or Mexico would be able to replace the DCPP generating capacity.

If power to replace DCPP capacity were to be purchased from sources outside California, the generating technology would likely be one of those described in the GEIS and would require the construction of new transmission facilities with their associated environmental impacts and costs. The description of the environmental impacts of other technologies in Chapter 8 of the GEIS is representative of the purchased power alternative to renewal of the DCPP operating licenses. Thus, the environmental impacts

[1] This estimate is based on recent PG&E gas-fired projects: Colusa Generating Station (1.29 million per MW), Humboldt Bay Generating Station (1.46 million per MW), and Tesla Generating Station (1.52 million per MW).

of purchased power would still occur but would be located elsewhere within the region, nation, or another country.

7.2.1.2 Alternatives that Do Not Meet System Generating Needs

This section identifies alternatives that PG&E deemed unreasonable, and the bases for these determinations. PG&E accounted for the fact that DCPP provides baseload generation and that any feasible alternative to DCPP would also need to be able to provide baseload power. In performing this evaluation, PG&E relied heavily upon NRC's GEIS (Reference 21).

Demand Side Management and Energy Efficiency
Demand-side management programs are designed to reduce customer energy consumption and overall electricity use. Because there would be no construction, there would be no new environmental impacts created from this alternative. Some programs also attempt to shift energy use to off-peak periods (Reference 11).

The CPUC supervises various demand-side management programs administered by the regulated utilities (including PG&E's Integrated Demand-Side Management Program, Reference 26), and many municipal electric utilities have their own demand-side management programs. The combination of these programs constitutes the most ambitious overall approach to reducing electricity demand administered by any state in the nation (Reference 11). To further coordinate and integrate demand-side management options for consumers, in 2008, the CPUC implemented a California Long-Term Energy Efficiency Strategic Plan (Reference 13).

Thus far, California's building efficiency standards (along with those for energy efficient appliances) have saved more than $56 billion in electricity and natural gas costs since 1978. It is estimated the standards will save an additional $23 billion by 2013 (Reference 14).

Reducing demand is an essential part of PG&E's operations. However, the available energy savings from these programs are insufficient to maintain service reliability to PG&E customers in the face of population and employment growth. Energy conservation would offset only a small fraction of the baseload energy supply lost by the shutdown of DCPP (Reference 11).

New Nuclear Reactor
California law prohibits the construction of any new nuclear power plants in California until the Energy Commission finds the federal government has approved and there exists a demonstrated technology for the permanent disposal of spent fuel from nuclear power facilities (Reference 9).

Coal-Fired Generation
In January 2007, the CPUC adopted an interim Greenhouse Gas (GHG) Emissions Performance Standard in an effort to help mitigate climate change. The Emissions

Performance Standard is a facility-based emissions standard requiring that all new long-term commitments for baseload generation serve California consumers with power plants that have emissions no greater than a combined-cycle gas turbine plant (1,100 pounds of CO_2 per megawatt-hour). "New long-term commitment" refers to new plant investments (new construction), new or renewal contracts with a term of 5 years or more, or major investments by the utility in its existing baseload power plants (Reference 12). With these standards in place, new coal-fired power generation technology is not an option in California. If and when carbon capture/sequestration technology becomes commercially viable, it may be appropriate to revisit the possibility of constructing and operating a coal-fired power plant in California.

Oil-Fired Generation
The Energy Information Administration (EIA) projects that oil-fired plants will account for very little of the new generating capacity in the U.S. during the 2008 to 2030 time frame because of continually rising fuel costs (Reference 17). In addition, the environmental impacts of operating current generation oil-fired power plants are similar to those from comparably sized coal-fired plants and are therefore not an option in California at this time. Thus, an oil-fired replacement for the capacity that would be lost if DCPP were to cease operations is not considered further in this discussion.

Wind
Wind turbines capture kinetic energy from the wind and use it to turn electric generators. Wind farms currently account for 1.3 percent of California's electrical capacity. Capacities of a single wind turbine range from 400 W up to 3.6 MW. Approximately 150,000 to 180,000 acres are required to produce 1,000 MW at a wind farm (Reference 27). This corresponds to a minimum site size of 342,000 to 411,000 acres for 2,285 MW of generation (Reference 27). Wind turbine "footprints" however, utilize only about 5 percent of the land on which the system is built. This allows for dual use of a site, such as for agriculture or ranching. A significant barrier to wind power development is the lack of available transmission access in areas with wind resources. Other challenges to siting wind farms are the bird mortality resulting from collisions with turbine blades, the noise of the rotors, and visual aesthetics. Because the power output can only be intermittently generated during the day or during certain seasons, depending on the location, wind turbines are unsuitable for baseload applications (Reference 11) and, therefore, wind generation cannot be considered an adequate replacement of DCPP generation. Moreover, as stated above, PG&E will need to pursue all feasible wind generation opportunities in order to meet California's aggressive renewable power requirements. It is unlikely that sufficient wind generation will be available to both meet those renewable power requirements and replace DCPP capacity with wind generation.

Solar Thermal
"Solar thermal power plants transform heat from the sun into mechanical energy, which is then used to generate electricity. The shape and structure of the solar collectors/reflectors varies depending on the technology employed. Parabolic trough collectors use long parabolic mirrors that focus the sunlight on a central tube containing

a heat transfer fluid, which is circulated back to a central power plant that houses a generator. Similarly, solar tower projects use a field of tracking mirrors that focus the sun on a central tower, where the heat transfer fluid is heated and then used to power electrical generation. A third technology, which is not fluid-based, uses a field of independently tracking parabolic mirrors, each of which focuses the sunlight on its own Stirling-cycle engine, which drives a small attached generator. Some of these facilities use conventional gas-fired steam boilers to generate supplemental electricity. The use of water for evaporative cooling can place a significant strain on limited water resources in arid areas and could potentially impact sensitive biological resources." (Reference 6)

The amount of acreage (habitat) required for each type of solar thermal technology varies. Assuming a parabolic trough system was located in a maximum solar exposure area, such as in a desert region, 500 acres per 100 MW (Reference 11) would be required. This corresponds to a site size of 11,425 acres for 2,285 MW of generation. While the plants do not generate problematic air emissions and have relatively low water requirements, construction of solar thermal plants leads to potential habitat destruction and substantial aesthetic changes. Solar thermal can be a good peak power source because it collects the sun's radiation during daylight hours and generates power during peak usage periods. Because solar thermal power is not available 24 hours per day, it is typically not acceptable for baseload applications (Reference 11). Moreover, as stated above, PG&E will need to pursue all feasible solar generation opportunities in order to meet California's aggressive renewable power requirements. It is unlikely that sufficient solar generation will be available to both meet those renewable power requirements and replace DCPP capacity with solar generation.

Photovoltaics
Photovoltaic (PV) power generation uses special semiconductor panels to directly convert sunlight into electricity. Arrays built from the panels can be mounted on the ground or on buildings where they can also serve as roofing material. Electricity generation from solar technologies, including both photovoltaic and solar thermal systems, currently totals about 0.3 percent of the state's electricity production. PV systems can have negative visual impacts, especially if ground mounted. Unless they are constructed as integral parts of buildings, PV systems require about four acres of ground area per MW of generation. Assuming that a PV system was located in a maximum solar exposure area, generation of 1,000 MW would require 54,000 acres. This corresponds to a site size of 123,390 acres for 2,285 MW of generation (Reference 27). PV installations are highly capital intensive and manufacturing of the panels generates hazardous wastes. Additionally, natural variation in sunlight intensity in a given location, and the limits of existing battery and capacitor technology, hinders the use of photovoltaics as a primary source of power in large industrial applications. Despite these limitations, the daytime power output of PV systems generally match California's peak electrical demand periods. The intermittent nature of the power, however, makes PV systems unsuitable for baseload applications (Reference 11). Moreover, as stated above, PG&E will need to pursue all feasible PV generation opportunities in order to meet California's aggressive renewable power requirements. It

is unlikely that sufficient PV generation will be available to both meet those renewable power requirements and replace DCPP capacity with PV generation.

Distributed Generation
According to the California Energy Commission, distributed generation is the widespread generation of electricity from facilities that are smaller than 50 MW in net generating capacity. Distributed generation units owned by PG&E or by industrial, commercial, institutional, or residential energy consumers would reduce the need for replacement generation. While distributed generation technologies are recognized as important resources to the region's ability to meet its long-term energy needs, distributed generation does not provide a means for PG&E to offset a substantial portion of the baseload energy lost by shutdown of DCPP.

Hydroelectric Power
Hydroelectric power uses the energy of falling water to turn turbines and generate electricity. Power production increases with both greater water flow and greater fall. California hydropower plants range in size from less than 0.1 MW to over 1,200 MW (Reference 11). Hydropower currently provides 13 percent of the state's electricity production, generally in baseload applications. Hydropower facilities typically require 14 acres per MW of generation (Reference 11). Production of 100 MW would require inundation of about 1,400 acres. This corresponds to a site size of 31,990 acres for 2,285 MW of generation. Hydropower generates no emissions or hazardous effluents and requires no fuel. However, development of new hydropower facilities is limited due to the severe environmental concerns and the lack of appropriate sites (Reference 11). Accordingly, hydroelectric power is not a reasonable alternative to renewal of the operating licenses for DCPP.

Geothermal
Geothermal power plants employ high pressure steam and hot water from naturally occurring subsurface geothermal reservoirs to drive turbines and generate electricity. Condensed steam and used water are injected back into the geothermal reservoir to sustain production. Geothermal plants account for approximately 5 percent of California's power and range in size from under 1 MW to 110 MW. Geothermal plants typically operate as baseload facilities and require 1 to 8 acres per MW (Reference 15). Generation of 100 MW would require at least 20 acres and many miles of new transmission facilities to deliver the power. This corresponds to an average of 9,140 acres for 2,285 MW of generation. Geothermal plants must be built near geothermal reservoir sites, because steam and hot water cannot be transported long distances without significant thermal energy loss. "The large amount of land needed to construct a geothermal plant implies altering current land uses of farming, ranching, forest, or natural habitat. Clearing this land would damage or destroy much of the existing habitat for wildlife, as well as pose potential adverse consequences for cultural resources. Some of the land originally cleared for construction of the geothermal facilities could probably be returned to previous uses, since it would not all be utilized by geothermal facilities. Much acreage would still be lost for the life of the plant, however, and this loss could be complicated by subsidence caused by withdrawal of the geothermal fluid."

(Reference 21) Newer geothermal technology uses reinjection of the geothermal fluid to maintain production, thereby reducing subsidence. Future geothermal development in California could occur in Imperial County, Lake County, and the northeastern and north-central portions of California (Reference 6). Geothermal plants offer baseload capacity similar to DCPP, but it is unlikely to be available on the scale required to replace the capacity of DCPP. Moreover, as stated earlier, PG&E will need to pursue all feasible geothermal opportunities in order to meet California's aggressive renewable power requirements. It is unlikely that sufficient geothermal generation will be available to both meet those renewable power requirements and replace DCPP capacity with geothermal generation.

Wood Energy
As discussed in the GEIS (Reference 21), the use of wood waste to generate electricity is largely limited to those states with significant wood resources. The pulp, paper, and paperboard industries in states with adequate wood resources generate electric power by consuming wood and wood waste for energy, benefiting from the use of waste materials that could otherwise represent a disposal problem.

Further, as discussed in Section 8.3.6 of the GEIS (Reference 21), construction of a wood-fired plant would have an environmental impact that would be similar to that for a coal-fired plant, although facilities using wood waste for fuel would be built on a smaller scale. Like coal-fired plants, wood-waste plants require large areas for fuel storage, processing, and waste (i.e., ash) disposal. Additionally, operation of wood-fired plants has environmental impacts, including impacts on the aquatic environment and air. Wood has a low heat content that makes it unattractive for baseload applications. It is also difficult to handle and has high transportation costs. Transportation of wood or wood wastes during the accumulation and delivery phases is generally dependent on the use of trucking on public roads. Reliance on vehicle transport for fuel supply can result in negative impacts to traffic and congestion near a generation facility, as well as the inherent additional air quality concerns resulting from truck fuel combustion emissions. Fuel transportation impacts are an added concern for most biomass related generation projects.

PG&E has concluded that, due to the lack of an environmental advantage, low heat content, handling difficulties, and high transportation costs, wood energy is not a reasonable alternative to DCPP license renewal.

Municipal Solid Waste
As discussed in Section 8.3.7 of the GEIS (Reference 21), the initial capital costs for municipal solid waste plants are greater than for comparable steam turbine technology at wood-waste facilities. This is due to the need for specialized waste separation and handling equipment.

The decision to burn municipal solid waste to generate energy is usually driven by the need for an alternative to landfills, rather than by energy considerations. The use of landfills as a waste disposal option is likely to increase in the near term. However, it is unlikely that many landfills will begin converting waste to energy because of unfavorable economics.

Estimates in the GEIS suggest that the overall level of construction impacts from a waste-fired plant should be approximately the same as that for a coal-fired plant. Additionally, waste-fired plants have the same or greater operational impacts (including impacts on the aquatic environment, air, and waste disposal). Some of these impacts would be moderate, but still larger than the environmental effects of DCPP license renewal.

PG&E has concluded that, due to the high costs and lack of environmental advantages, burning municipal solid waste to generate electricity is not a reasonable alternative to DCPP license renewal.

Other Biomass-Derived Fuels

In addition to wood and municipal solid waste fuels, there are several other concepts for fueling electric generators, including burning energy crops, converting crops to a liquid fuel such as ethanol (ethanol is primarily used as a gasoline additive), and gasifying energy crops (including wood waste and manure). As discussed in the GEIS, none of these technologies has progressed to the point of being competitive on a large scale or of being reliable enough to replace a baseload plant such as DCPP.

PG&E has concluded that, due to the high costs and lack of environmental advantage, burning other biomass-derived fuels is not a reasonable alternative to DCPP license renewal.

Fuel Cells

Fuel cells convert the energy from a chemical reaction between a fuel (such as hydrogen) and an oxidizer (such as oxygen) into electricity. Fuel cells have ultra-low air emissions, and operate similar to batteries but do not run down or require recharging. They run as long as fuel and oxidizer are supplied to them, and can operate using fuel gases from biomass conversion. Even small fuel cells can perform at high efficiencies. Fuel cell power plants from 10 kW to 3 MW have been field demonstrated in California.

Many fuel cell power plants require a fossil fuel such as natural gas to operate and thus must be located where the fuel can be delivered. In general, fuel cell plants require more land than combined-cycle power plants, but emit about the same amount of carbon dioxide. No water-cooled systems are required by fuel cells. Thus, water use and thermal discharges are avoided. Fuel cells generate some hazardous waste, including periodic removal and disposal of absorption beds. The elevated pressures (3 to 7 atmospheres) and explosion hazards of fuels such as hydrogen or natural gas present some public safety issues (Reference 11). Even if fuel cell technology matures over the next 10-15 years to the point where it can be used on an industrial scale, it would not be a reasonable replacement for DCPP capacity.

Delayed Retirement
As the NRC noted in the GEIS (Reference 21), extending the lives of existing non-nuclear generating plants beyond the time they were originally scheduled to be retired represents another potential alternative to license renewal. Fossil plants slated for retirement tend to be ones that are old enough to have difficulty in meeting today's restrictions on air contaminant emissions. Additionally, these older units are likely relatively inefficient, having high fossil fuel consumption profiles, which do not optimize energy recovery from combustion in comparison to newer technologies. In the face of increasingly stringent environmental restrictions, and likely increasing fossil fuel scarcity and costs, delaying retirement in order to compensate for a plant the size of DCPP would be unreasonable without major construction to upgrade or replace plant components. PG&E currently has no plans for retiring any of its fleet of power plants and expects to need additional fuel efficient generating capacity in the near future.

7.2.2 ENVIRONMENTAL IMPACTS OF ALTERNATIVES THAT MEET SYSTEM GENERATING NEEDS

This section evaluates the environmental impacts of alternatives that PG&E has determined to be reasonable alternatives to DCPP license renewal: natural gas-fired generation and purchased power.

7.2.2.1 Natural Gas-Fired Generation

NRC evaluated environmental impacts from gas-fired generation alternatives in the GEIS, focusing on combined-cycle plants. Section 7.2.1.1 presents PG&E's reasons for defining the gas-fired generation alternative as a combined-cycle plant on the DCPP site or at another location within PG&E's service region. Reduced land requirements, due to a smaller facility footprint, would reduce impacts to ecological, aesthetic, and cultural resources. A smaller workforce could have socioeconomic impacts in the surrounding communities. Human health effects associated with air emissions would be of concern. Aquatic biota losses due to cooling water withdrawals would be reduced by the concurrent shutdown of the DCPP nuclear Units. This assumes that new mechanical-draft cooling towers would need to be constructed to support the new closed cycle cooling system.

In the GEIS Supplement for Donald C. Cook Nuclear Plant (Reference 24), NRC evaluated the environmental impacts of constructing and operating four 468-MWe combined-cycle gas-fired units as an alternative to a nuclear power plant license renewal. PG&E has reviewed the NRC analysis, believes it to be sound, but notes that it analyzed less generating capacity than the 2,285 MWe of net power discussed in this analysis. In defining the DCPP gas-fired alternative, PG&E has used site and California-specific input and has scaled from the NRC analysis, where appropriate. In order to adequately replace the entire net generation of DCPP, four 562.5-MWe combined-cycle plants would be required (total net generation capacity of 2,250 MWe). The conceptual replacement units are comparable to the type of combined-cycle non-duct fired fossil fuel generation units recently constructed in California (Moss Landing

Power Plant – 530 MWe [Reference 1], Contra Costa Power Plant – 530 MWe [Reference 2], and Colusa Power Plant – 660 MWe [Reference 7]).

Air Quality
Natural gas is a relatively clean-burning fossil fuel that primarily emits nitrogen oxides (NO_x), a regulated pollutant, during combustion. A natural gas-fired plant would also emit small quantities of sulfur oxides (SO_x), particulate matter, and carbon monoxide, all of which are regulated pollutants. Control technology for gas-fired turbines focuses on NO_x emissions. More significant would be the emission of green house gases (GHG), primarily carbon dioxide (CO_2). PG&E estimates the gas-fired alternative emissions to be as follows:

SO_x = 199 tons per year

NO_x = 638 tons per year

Carbon Monoxide = 134 tons per year

Particulates = 111 tons per year

Carbon Dioxide = 8,780,805 tons per year

Table 7.2-1 shows how PG&E calculated these emissions.

NO_x effects on ozone levels, SO_2 allowances, and NO_x emission offsets could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, and regulatory requirements are less stringent, the emissions are still substantial. PG&E concludes that emissions from the gas-fired alternative at DCPP or an alternative site would noticeably alter local air quality, but would not destabilize regional resources (i.e., air quality). Air quality impacts would therefore be moderate.

However, the substantial GHG emissions from new fossil generation would be counterproductive to the State plan for reduction of global warming emissions from both industrial and non-industrial activities. California Assembly Bill 32, "The California Global Warming Solutions Act of 2006," requires the State to reduce GHG emissions to 1990 levels by 2020. Moreover, by Executive Order S-20-06, dated October 18, 2006, California must reduce GHG emissions 80 percent below 1990 levels by 2050. The power generation industry is currently a major component of existing GHG sources. Approval for construction and operation of new industrial sources could be significantly hindered by these adopted environmental requirements.

Waste Management
The solid waste generated from this type of facility would be minimal. There will be spent selective catalytic reduction catalyst used from NO_x control and small amounts of solid-waste products (i.e. ash) from burning natural gas fuel. In the GEIS, the NRC staff

concluded that waste generation from gas-fired plants would be minimal (Reference 21). Gas-fired plants produce very few combustion by-products because of the clean nature of the fuel. Waste-generation impacts would be so minor that they would not noticeably alter any important resource attribute. Construction-related debris would be generated during construction activities. Overall, the waste impacts at the DCPP site or an alternative site would be small for a natural gas-fired plant (Reference 24).

Land Use
Approximately 25 to 30 acres of land would be needed to construct and operate a typical 500 MW combined-cycle power plant (Reference 3). PG&E owns sufficient land at the DCPP site if needed for this purpose. However, the topography of the site would require significant excavation and grading that would substantially increase the costs of such a project in comparison to implementation at more flat, accommodating, locations. Multiple units would likely have to be placed at tiered elevations. PG&E assumed that this alternative would use the existing switchyard, offices, and transmission line ROWs. However, new mechanical-draft cooling towers would need to be constructed to support closed cycle cooling systems for the essentially new generation facilities. Additionally, existing plant structures occupy much of the available buildable land, therefore, any replacement would require decommissioning and removal of existing structures, further complicating such an effort. The existing DCPP footprint would not be available for replacement of the DCPP baseload without a significant time lag.

The environmental impacts of locating the gas-fired generation facility at an alternate location would depend on the past use of the location. If the site is a previously undisturbed site the impacts would be more significant than if the site was a previously developed site. Construction and operation of the gas-fired facility at an undeveloped site would require construction of a new cooling system, switchyard, offices, gas transmission pipelines, and transmission line ROWs. A previously industrial site may have closer access to existing infrastructure, which would help to minimize environmental impacts. A gas-fired alternative constructed at the DCPP site would have direct access to a transmission system and offices.

Other Impacts
As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized using best management practices. PG&E estimates a peak construction workforce of approximately 650 per plant, therefore socioeconomic impacts of construction would be minimal. However, since PG&E estimates a workforce of 31 per plant for gas operations (Reference 7), the reduction in overall long-term site workforce would result in adverse socioeconomic impacts. PG&E believes these impacts would be small to moderate.

Combined-cycle power plants using evaporative cooling consume about 6 acre-feet of either fresh or recycled/reclaimed water per year per MW based on expected capacity factors. In addition, a new high efficiency combined-cycle power plant would burn approximately 3.25 million cubic feet of natural gas per hour. The natural gas would need to be delivered through a pipeline system that can support the level of natural gas needed for a baseload power plant. See Figure 7.2-3 for an illustration of the natural gas pipeline infrastructure in California, which may facilitate the delivery of natural gas to a replacement baseloaded power plant in the absence of the power normally distributed by DCPP (Reference 11). Regardless of where the natural gas-fired plant is built, additional land would be required for natural gas wells and collection stations. Approximately 7,578 acres would be needed for wells and stations (Reference 21).

Any large scale replacement generation facilities would need to connect to the PG&E transmission grid, which is currently configured to receive a large proportion of power from DCPP. This network would need to be rerouted to reflect the changed generation locations. Alternatively, new transmission facilities could be used as a substitute for some in-State generation by improving access to generation in the Pacific Northwest and Southwestern states (Reference 11). Major 500 kV transmission components connect DCPP to the Gates Substation in Fresno County and the Midway Substation in Kern County. Shutdown of DCPP would result in significant changes in load flow and likely result in reduced utilization of the existing interconnecting lines, which would necessitate significant reconfiguration of the transmission grid in those areas.

Developing new transmission facilities requires roughly ten years of advance planning. Demonstrating need, securing environmental approvals, permits, and rights-of-way, and construction activities contribute to the long lead-time needed for transmission planning. Because of the difficulty of securing new rights-of-way, replacement transmission facilities would likely, in part, follow existing major paths (Reference 11).

Impacts to aquatic resources and water quality at the DCPP site would be smaller than the impacts of DCPP operations, due to the projected necessary use of mechanical-draft cooling towers that would be constructed to support the closed cycle cooling systems. However, the additional stacks and boilers would increase the visual impact of the existing site. Impacts to cultural and ecological resources would be likely due to construction of a new natural gas pipeline on previously disturbed land. Additionally, use of closed cycle cooling systems with saltwater makeup would result in substantial air emissions from cooling towers.

PG&E estimates that other construction and operation impacts of combined-cycle plants would be small. In most cases, the impacts would be detectable, but they would not destabilize any important attribute of the resource involved.

7.2.2.2 Purchased Power

As discussed in Section 7.2.1.1, PG&E assumes that the generating technology used under the purchased power alternative would be one of those that NRC analyzed in the GEIS. PG&E is also adopting by reference the NRC analysis of the environmental impacts from those technologies. Under the purchased power alternative, therefore, environmental impacts would still occur, but they would likely originate from a power plant located elsewhere in California or other states in the West.

7.3 REFERENCES

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TABLE 7.2-1

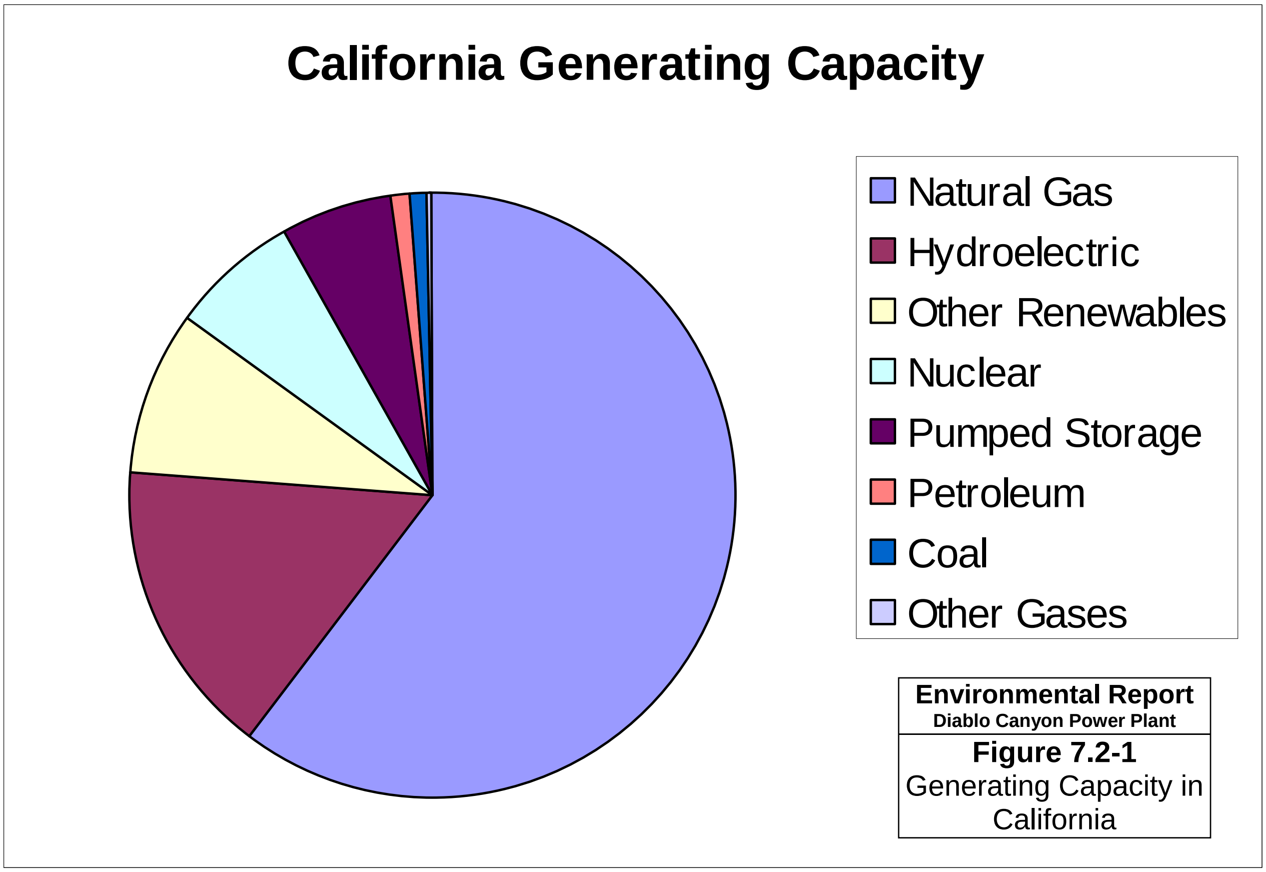
AIR EMISSIONS FROM NATURAL GAS-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual Gas Consumption	$4 units\ x \frac{562.5MW}{unit} x \frac{6{,}600 Btu}{kWxhr} x\, 0.9 x \frac{ft^3}{1{,}015 Btu} x \frac{7{,}884 hr}{year}$	115,347,192,118 ft^3 per year
Annual Btu Input	$\frac{115{,}347{,}192{,}118\, ft^3}{year} x \frac{1{,}015 Btu}{ft^3} x \frac{MMBtu}{10^6\, Btu}$	117,077,400 MMBtu per year
SO_X[a]	$\frac{0.0034 lb}{MMBtu} x \frac{ton}{2{,}000 lb} x \frac{117{,}077{,}400 MMBtu}{year}$	199 tons SO_X per year
NO_X[b]	$\frac{0.0109 lb}{MMBtu} x \frac{ton}{2{,}000 lb} x \frac{117{,}077{,}400 MMBtu}{year}$	638 tons NO_X per year
CO[b]	$\frac{0.0023 lb}{MMBtu} x \frac{ton}{2{,}000 lb} x \frac{117{,}077{,}400 MMBtu}{year}$	134 tons CO per year
PM[a]	$\frac{0.0019 lb}{MMBtu} x \frac{ton}{2{,}000 lb} x \frac{117{,}077{,}400 MMBtu}{year}$	111 tons filterable PM per year
CO_2[c]	$4 units\ x \frac{562.5MW}{unit} x \frac{1{,}100\ lb\ CO_2}{MWxhr} x\, 0.9 x \frac{ton}{2{,}000 lb} x \frac{7{,}884 hr}{year}$	8,780,805 tons CO_2 per year

* 0.9 = 90% Baseload Capacity Factor: This provides for 36 Days/Year for planned maintenance outages and unplanned forced outages. This is comparable to current capacity factors (inclusive of refueling outages) for DCPP Units 1 & 2.

a. Reference 20, Table 3.1-1
b. Reference 20, Table 3.2-2
c. Reference 12

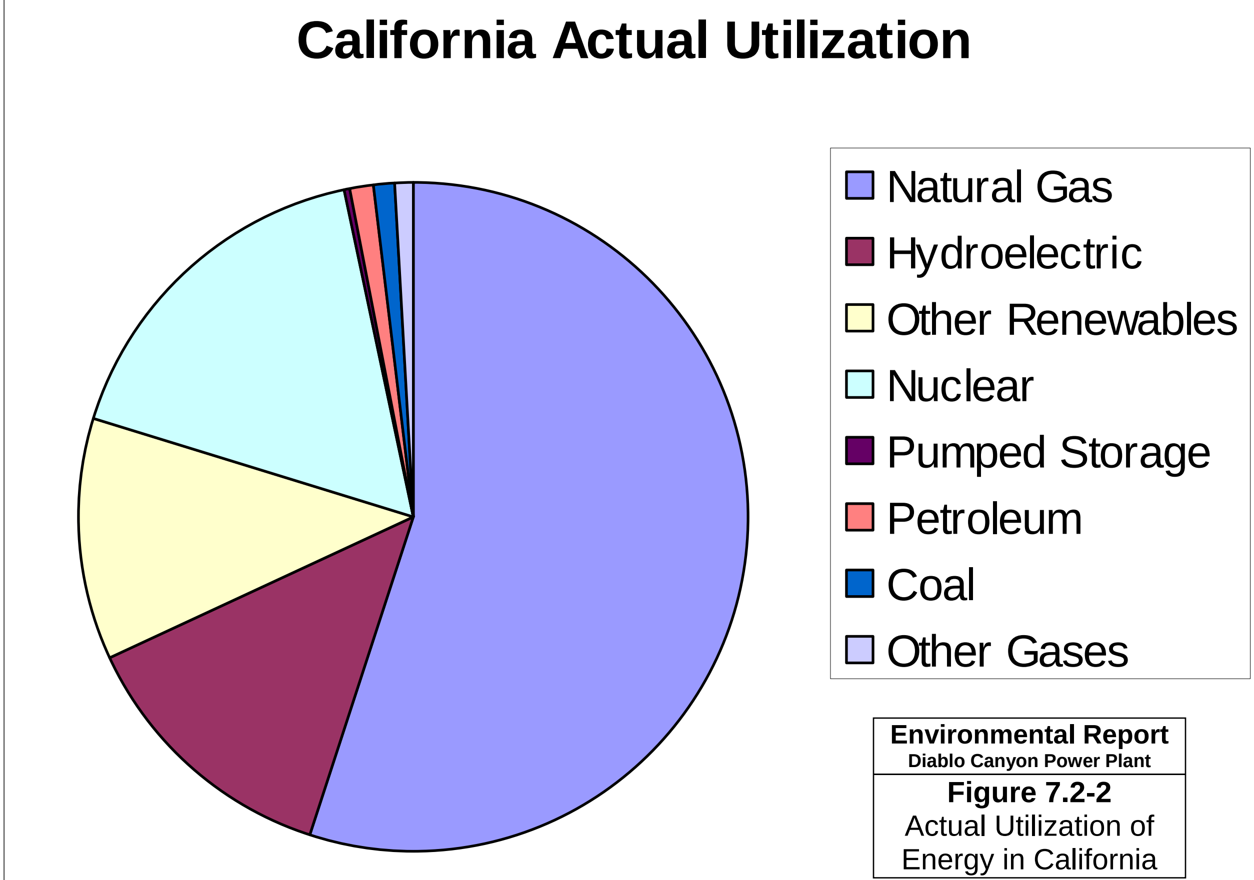
SO_X = oxides of sulfur
NO_X = oxides of nitrogen
CO = carbon monoxide
PM = particulate
CO_2 = carbon dioxide



Environmental Report
Diablo Canyon Power Plant

Figure 7.2-1
Generating Capacity in California

Source: Reference 19



Environmental Report
Diablo Canyon Power Plant
Figure 7.2-2
Actual Utilization of Energy in California

Source: Reference 19

Environmental Report **Diablo Canyon Power Plant**
Figure 7.2-3 Natural Gas Pipeline Layout in California

CHAPTER 8 – COMPARISON OF ENVIRONMENTAL IMPACTS OF LICENSE RENEWAL WITH THE ALTERNATIVES

NRC

"To the extent practicable, the environmental impacts of the proposal and the alternatives should be presented in comparative form..." 10 CFR 51.45(b)(3) as adopted by 51.53(c)(2)

Chapter 4 analyzes environmental impacts of DCPP license renewal and Chapter 7 analyzes impacts from renewal alternatives. Table 8-1 summarizes environmental impacts of the proposed action (license renewal) and the alternatives that PG&E has determined to be reasonable alternatives, for comparison purposes. The environmental impacts compared in Table 8-1 are those that are either Category 2 issues for the proposed action, license renewal, or are issues that the Generic Environmental Impact Statement (GEIS) (Reference 1) identified as major considerations in an alternatives analysis. For example, although the NRC concluded that air quality impacts from the proposed action would be small (Category 1), the GEIS identified major human health concerns associated with air emissions from alternatives (Section 7.2.2). Therefore, Table 8-1 compares air impacts among the proposed action and the alternatives. Table 8-2 is a more detailed comparison of the alternatives.

PG&E's evaluation of alternatives concluded that the environmental impacts of the continued operation of DCPP are smaller than those impacts associated with reasonable alternatives.

8.1 REFERENCES

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TABLE 8-1
IMPACTS COMPARISON SUMMARY

			Alternatives	
Impact Category	**Proposed Action (License Renewal)**	**Decommissioning**	**Natural Gas-Fired Generation**	**Purchased Power**
Land Use	SMALL	SMALL	SMALL	MODERATE
Water Quality	SMALL	SMALL	SMALL	SMALL to MODERATE
Air Quality	SMALL	SMALL	MODERATE	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	SMALL to MODERATE	SMALL to MODERATE
Threatened or Endangered Species	SMALL	SMALL	SMALL to MODERATE	SMALL
Human Health	SMALL	SMALL	SMALL	SMALL to MODERATE
Socioeconomics	SMALL	SMALL	SMALL to MODERATE	SMALL to MODERATE
Waste Management	SMALL	SMALL	SMALL	SMALL to MODERATE
Aesthetics	SMALL	SMALL	SMALL	SMALL to MODERATE
Cultural Resources	SMALL	SMALL	SMALL to MODERATE	SMALL

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.
MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource. 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.

TABLE 8-2
IMPACTS COMPARISON DETAIL

		Alternatives	
Proposed Action (License Renewal)	**Base (Decommissioning)**	**Natural Gas-Fired Generation**	**Purchased Power**
Alternative Descriptions			
DCPP license renewal for 20 years, followed by decommissioning	Decommissioning following expiration of current DCPP licenses. Adopting the GEIS description by reference (Reference 1) as comparable to DCPP decommissioning.	New construction at the DCPP site.	Would involve construction of new generation capacity in the region. Adopting by reference GEIS description of alternate technologies (Section 7.2.1.1)
		Assuming PG&E can use existing Diablo-Gates transmission line rights-of-way and connect to the gas pipeline for the Morro Bay Power Plant, approximately 15 miles would need to be constructed[1]	
		Use existing switchyard and transmission lines.	Construct transmission lines from available power sources located within the State or Pacific Northwest Region.
		Four 562.5-MW of net power (Combined-cycle turbines to be used); capacity factor 0.90	
		New mechanical-draft cooling towers would need to be constructed to support the closed cycle cooling systems.	

[1] Connection to the existing pipeline is feasible, assuming the pipeline has the capacity to support the 4 combined-cycle units at DCPP.

TABLE 8-2
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	Base (Decommissioning)	Alternatives: Natural Gas-Fired Generation	Alternatives: Purchased Power
		Natural gas, 1,015 Btu/ft^3; 6,600 Btu/kWh; 0.0034 lb SO_x/MMBtu; 0.0109 lb NO_x/MMBtu; 115,347,192,118 ft^3 gas/yr Selective catalytic reduction with steam/water injection	
1,350 permanent employees		31 workers per plant (Section 7.2.2.1)	
Land Use Impacts			
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 52, 53)	SMALL – Not an impact evaluated by GEIS (Reference 1)	SMALL – 25 to 30 acres per facility at DCPP location; pipeline could be routed along existing transmission line corridors and could require an additional 90 to 100 acres for easements (Section 7.2.2.1)	MODERATE – In part, most transmission facilities could be constructed along existing transmission corridors (Section 7.2.2.2) Adopting by reference GEIS description of land use impacts from alternate technologies (Reference 1)
Water Quality Impacts			
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 3, 4, 6-12, 32, and 37). Five Category 2 groundwater issues not applicable (Section 4.1, Issue 13; Section 4.5, Issue 33; Section 4.6, Issue 34; Section 4.7, Issue 35; and Section 4.8, Issue 39)	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 89)	SMALL – Reduced cooling water demands, inherent in combined-cycle design (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of water quality impacts from alternate technologies (Reference 1)

TABLE 8-2
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	Base (Decommissioning)	Alternatives: Natural Gas-Fired Generation	Alternatives: Purchased Power
Air Quality Impacts			
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issue 51). One Category 2 issue not applicable (Section 4.11, Issue 50).	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 88)	MODERATE – 199 tons SO_x/yr 638 tons NO_x/yr 134 tons CO/yr 111 tons PM_{10}/yr[a] 8,780,805 tons CO_2/yr (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of air quality impacts from alternate technologies (Reference 1)
Ecological Resource Impacts			
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 15-24, 45-48). One Category 2 issue not applicable (Section 4.9, Issue 40). DCPP holds a current NPDES Permit, which constitutes compliance with Clean Water Act Section 316(b) (Section 4.2, Issue 25; Section 4.3, Issue 26; and Section 4.4, Issue 27).	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 90)	SMALL to MODERATE – Construction of the pipeline could alter habitat. (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of ecological resource impacts from alternate technologies (Reference 1)
Threatened or Endangered Species Impacts			
SMALL – Several federally-listed threatened, endangered, or candidate species are known to occur in the vicinity of the DCPP site or along the transmission corridors. PG&E is currently unaware of any	SMALL – Not an impact evaluated by GEIS (Reference 1)	SMALL to MODERATE – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats. However, routing of the proposed natural gas pipeline could potentially	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats

TABLE 8-2
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	Base (Decommissioning)	Alternatives: Natural Gas-Fired Generation	Alternatives: Purchased Power
adverse issues that involve threatened or endangered species associated with the operation and/or maintenance of DCPP, including the existing transmission lines, towers, and access roads (Section 4.10, Issue 49).		affect those species in the Morro Bay Estuary.	
Human Health Impacts			
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issue 56, 58, 61, 62). The issue of microbiological organisms (Section 4.12, Issue 57) does not apply. Risk due to transmission line-induced currents are minimal due to conformance with consensus code (Section 4.13, Issue 59).	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 86)	SMALL – Adopting by reference GEIS conclusion that some risk of cancer and emphysema exists from emissions (Reference 1)	SMALL to MODERATE – Adopting by reference GEIS description of human health impacts from alternate technologies (Reference 1)
Socioeconomic Impacts			
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 64, 67). Two Category 2 issues are not applicable (Section 4.16, Issue 66 and Section 4.17.1, Issue 68). Location in medium population area with no growth controls	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 91)	SMALL to MODERATE – Reduction in permanent work force at DCPP could affect surrounding counties (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of socioeconomic impacts from alternate technologies (Reference 1)

TABLE 8-2
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	Base (Decommissioning)	Alternatives: Natural Gas-Fired Generation	Alternatives: Purchased Power
minimizes potential for housing impacts (Section 4.14, Issue 63). Plant property tax payment represents 6 percent of county's total tax revenues (Section 4.17.2, Issue 69). Capacity of public water supply and transportation infrastructure minimizes potential for related impacts (Section 4.15, Issue 65 and Section 4.18, Issue 70).			
Waste Management Impacts			
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 77-85)	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 87)	SMALL – Almost no waste generation (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of waste management impacts from alternate technologies (Reference 1)
Aesthetic Impacts			
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 73, 74)	SMALL – Not an impact evaluated by GEIS (Reference 1)	SMALL – Steam turbines and stacks would create visual impacts comparable to those from existing DCPP facilities (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of aesthetic impacts from alternate technologies (Reference 1)
Cultural Resource Impacts			
SMALL – SHPO consultation minimizes potential for impact (Section 4.19, Issue 71)	SMALL – Not an impact evaluated by GEIS (Reference 1)	SMALL to MODERATE – Impacts to cultural resources would be likely due to undeveloped nature of the proposed natural gas pipeline connection (Section 7.2.2.1)	SMALL – Adopting by reference GEIS description of cultural resource impacts from alternate technologies (Reference 1)

TABLE 8-2
IMPACTS COMPARISON DETAIL

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.
MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource. 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.

Btu = British thermal unit
CO = carbon monoxide
CO_2 = carbon dioxide
ft^3 = cubic foot
gal = gallon
GEIS = Generic Environmental Impact Statement (NRC 1996)
kW-h = kilowatt-hour
lb = pound
MM = million
MW = megawatt
NO_x = nitrogen oxide
PM_{10} = particulates having diameter less than 10 microns
SHPO = State Historic Preservation Officer
SO_x = oxides of sulfur
TSP = total suspended particulates
yr = year

a. All TSP for gas-fired alternative is PM_{10}

CHAPTER 9 – STATUS OF COMPLIANCE

9.1 PROPOSED ACTION

NRC

"The environmental report shall list all Federal permits, licenses, approvals and other entitlements which must be obtained in connection with the proposed action and shall describe the status of compliance with applicable environmental quality standards and requirements including, but not limited to, applicable zoning and land-use regulations, and thermal and other water pollution limitations or requirements which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection…" 10 CFR 51.45(d) as adopted by 10 CFR 51.53(c)(2)

9.1.1 GENERAL

Table 9-1 lists environmental authorizations that PG&E has obtained for current DCPP operations. In this context, PG&E uses "authorizations" to include any permits, licenses, approvals, or other entitlements. PG&E expects to continue renewing these authorizations during the current license period. PG&E is in compliance with applicable environmental standards and requirements.

Table 9-2 lists additional environmental authorizations and consultations related to NRC renewal of the DCPP licenses to operate. As indicated, PG&E anticipates needing relatively few such authorizations and consultations. Sections 9.1.2 through 9.1.5 discuss some of these items in more detail.

9.1.2 THREATENED OR ENDANGERED SPECIES

Section 7 of the Endangered Species Act (16 USC 1536) requires federal agencies to ensure that agency action is not likely to jeopardize any species that is listed or proposed for listing as threatened or endangered. If review of the proposed action indicates the potential for adversely affecting listed or candidate species, the federal agency must consult with the U.S. Fish and Wildlife Service (USFWS) regarding effects on non-marine species, the National Marine Fisheries Service (NMFS) for marine species, or both. USFWS and NMFS have issued joint procedural regulations at 50 CFR 402, Subpart B, that address consultation, and USFWS maintains the joint list of threatened and endangered species at 50 CFR 17.

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

USFWS, NMFS, California Department of Fish and Game (CDF&G), State Lands Commission (SLC), and Bureau of Land Management (BLM).

9.1.3 HISTORIC PRESERVATION

Section 106 of the National Historic Preservation Act (16 USC 470f) requires federal agencies having the authority to license any undertaking to, prior to issuing the license, take into account the effect of the undertaking on historic properties and to afford the Advisory Council on Historic Preservation an opportunity to comment on the undertaking. Although not required of an applicant by federal law or NRC regulation, PG&E has chosen to invite comment by the California SHPO. Attachment D includes a copy of PG&E correspondence with the SHPO regarding potential effects that DCPP license renewal might have on cultural resources. The SHPO requested that DCPP develop a Programmatic Agreement and Historic Resources Management Plan to replace the current Archaeological Resources Management Plan.

9.1.4 COASTAL ZONE MANAGEMENT PROGRAM COMPLIANCE

The federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on applicants for a federal license to conduct an activity that could affect a state's coastal zone. The Act requires the applicant to certify to the licensing agency that the proposed activity would be consistent with the state's federally approved coastal zone management program [16 USC 1456(c)(3)(A)]. The National Oceanic and Atmospheric Administration has promulgated implementing regulations that indicate that the requirement is applicable to renewal of federal licenses for activities not previously reviewed by the state [15 CFR 930.51(b)(1)]. The regulation requires that the license applicant provide its certification to the federal licensing agency and a copy to the applicable state agency [15 CFR 930.57(a)].

California has a coastal zone management program and DCPP, located in San Luis Obispo County, is within the California coastal zone. Therefore, concurrence from the California Coastal Commission (CCC) is necessary. The certification prepared by PG&E is in Attachment E. PG&E is awaiting concurrence of the certification by the CCC.

9.1.5 WATER QUALITY (401) COMPLIANCE

Federal Clean Water Act (CWA) Section 401 requires an applicant for a federal license to conduct an activity that might result in a discharge into navigable waters to provide the licensing agency a certification from the state that the discharge will comply with applicable Clean Water Act requirements (33 USC 1341). NRC has indicated in its *Generic Environmental Impact Statement for License Renewal* (GEIS) (Reference 1) that issuance of a National Pollutant Discharge Elimination System (NPDES) permit implies certification by the state.

Consistent with the GEIS, PG&E is providing DCPP's NPDES permit, in Attachment B, as evidence of state water quality (401) certification. As discussed in Section 4.2, the

Central Coast Regional Water Quality Control Board (CCRWQCB) issued a NPDES Permit (CA0003751) to PG&E in 1990. The permit was due to expire in 1995 and has since been in administrative extension. PG&E is actively working with the CCRWQCB to renew this permit. In accordance with permit requirements, PG&E monitors discharge characteristics and reports the results to the CCRWQCB.

9.2 ALTERNATIVES

NRC

"…The discussion of alternatives in the report shall include a discussion of whether alternatives will comply with such applicable environmental quality standards and requirements." 10 CFR 51.45(d) as adopted by 10 CFR 51.53(c)(2)

The gas and purchased power alternatives discussed in Chapter 7 could potentially be constructed and operated to comply with all applicable environmental quality standards and requirements. PG&E notes that increasingly stringent air quality protection requirements could make the construction of a large fossil-fueled power plant infeasible in many locations. PG&E also notes that the U.S. Environmental Protection Agency has new requirements for the design and operation of cooling water intake structures at new and existing facilities (40 CFR 125 Subparts I and J). The requirements would necessitate construction of cooling towers for the gas-fired alternative if surface waters could no longer be used for once-through cooling.

9.3 REFERENCES

1. NUREG-1437: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS), Volumes 1 and 2, U.S. Nuclear Regulatory Commission. Washington, D.C., May 1996.

TABLE 9-1

ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT DCPP OPERATIONS

Agency	Authority	Requirement	Number	Issue or Expiration Date[1]	Activity Covered
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.), 10 CFR 50.10	License to Operate	DPR– 80 – Unit 1 DPR– 82 – Unit 2	Issued 11/02/1984 Expires 11/02/2024 Issued 11/26/1985 Expires 08/26/2025	Operation of Units 1 and 2
Central Coast Regional Water Quality Control Board	Clean Water Act (33 USC 1251 et seq.)	California Pollutant Discharge Elimination System Permit	CA0003751	Issued 05/11/1990 Expired 07/01/1995 (in administrative extension)	Plant discharges to the Pacific Ocean
State Lands Commission	Public Resources Code 4307.9	Lease	2231-10-0044	Issued 08/28/1969 Expires 08/28/2018	Lease for Breakwaters
State Lands Commission	Public Resources Code 4449.9	Right-of-Way	2231-10-0048	Issued 06/01/1970 Expires 06/01/2019	Right-of-Way for Breakwaters
Department of Interior	Bureau of Land Management	Right-of-Way	2231-10-0041	Issued 08/22/1969 Expires 08/22/2018	Right-of-Way for Construction and Maintenance of Breakwaters
California Department of Toxic Substances Control	Ca H&S Code Section 25200, CCR Title 22 Division 4.5.	RCRA Equivalent Waste Treatment Storage & Disposal (TSDF) Permit	CAD077966349	Issued 11/16/2006 Expires 07/30/2016	Operation of Hazardous Waste Facility at DCPP
San Luis Obispo County Environmental Health Department	N/A	Underground Storage Tank Operating Permit & Hazardous Materials Handler Authorization	40-000-17604-006 40-000-17604-002	Issued 01/01/2009 Expires 12/31/2009	Operation of Diesel Storage Tanks

[1] Issuance and expiration dates are accurate as of 08/30/2009.

TABLE 9-1

ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT DCPP OPERATIONS

Agency	Authority	Requirement	Number	Issue or Expiration Date[1]	Activity Covered
National Marine Fisheries Service	Endangered Species Act of 1973 (16 USC 1531-1544)	Biological Opinion and Incidental Take Statement		Issued 09/18/2008 Expires 08/26/2025	Possession and disposition of impinged or stranded sea turtles
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	919-3	Issued 07/21/2009 Expires 06/30/2010	Operation of the Emergency Diesel Generators (DCPP)
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	886-1	Issued 04/30/2009 Expires 03/31/2010	Operation of the Emergency Diesel Generator (EOF)
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	49-1	Issued 07/21/2009 Expires 06/30/2010	Operation of the Auxiliary Boiler
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	533-2	Issued 07/21/2009 Expires 06/30/2010	Operation of the Abrasive Blast Facility
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	338-1	Issued 07/21/2009 Expires 06/30/2010	Operation of a Paint Spray Booth
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	415-1	Issued 08/22/2007 Expires 06/30/2010	Operation of Portable Sandblast Devices
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	546-1	Issued 08/05/2009 Expires 07/31/2010	Operation of a non-retail gasoline dispensing facility

TABLE 9-1

ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT DCPP OPERATIONS

Agency	Authority	Requirement	Number	Issue or Expiration Date[1]	Activity Covered
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	1065-5	Issued 07/21/2009 Expires 06/30/2010	Operation of a transportable diesel-fueled internal combustion unit
San Luis Obispo County Public Health Department	Safe Drinking Water Act (42 USC 300 F, et seq.)	Non-Community Drinking Water System Permit	PT 0004769	N/A	Authorization to operate non-community drinking and domestic water system
Port San Luis Harbor District	N/A	Lease Agreement	2232-11-0041 2232-11-0037 2232-11-0038	Issued 07/01/1986 Expires 06/30/2011	For access road enlargement and siren location
California Secretary of Resources	California Department of Fish and Game	License	710027-01	Issued 04/23/2009 Expires 12/31/2009	Surface Canopy Kelp Harvesting
California Secretary of Resources	California Department of Fish and Game	Special Use Permit	710006-02	Issued 12/31/1999 Does not expire	Removal of Benthic Kelp from the DCPP Intake Cove Exclusion Zone

TABLE 9-2

ENVIRONMENTAL AUTHORIZATIONS FOR DCPP LICENSE RENEWAL

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License Renewal	Environmental Report submitted in support of license renewal application.
U.S. Fish and Wildlife Service (USFWS)	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires federal agency issuing a license to consult with USFWS (Attachment C).
California Central Coast Regional Water Quality Control Board	Clean Water Act Section 401 (33 USC 13411)	Certification	State issuance of NPDES permit (Section 9.1.5) constitutes 401 certification (Attachment B)
California Coastal Commission	Federal Coastal Zone Management Act (16 USC 1452 et seq.)	Certification	Requires applicant to prove certification to Federal agency issuing the license renewal would be consistent with the Federally approved State Coastal Zone Management program. Based on its review of the proposed activity, the State must concur with or object to the applicant's certification (Attachment E).
California State Office of Historic Preservation	National Historic Preservation Act Section 106 (16 USC 470f)	Consultation	Requires federal agency issuing a license to consider impacts to historical properties and consult with State Historic Preservation Officer (SHPO). SHPO must concur that license renewal will not affect any sites listed or eligible for listing (Attachment D).

ATTACHMENT A - NRC NEPA ISSUES FOR LICENSE RENEWAL OF NUCLEAR POWER PLANTS

PG&E has prepared this environmental report in accordance with the requirements of NRC regulation 10 CFR 51.53. NRC included in the regulation a list of National Environmental Policy Act (NEPA) issues for license renewal of nuclear power plants.

Table A-1 lists these 92 issues and identifies the section in which PG&E addressed each applicable issue in this environmental report. For organization and clarity, PG&E has assigned a number to each issue and uses the issue numbers throughout the environmental report.

TABLE A-1 Sheet 1 of 9

DCPP ENVIRONMENTAL REPORT CROSS-REFERENCE OF LICENSE RENEWAL NEPA ISSUES

Issue[a]	Category	Section of this Environmental Report	GEIS Section/Page[b]
Surface Water Quality, Hydrology, and Use (for all plants)			
1. Impacts of refurbishment on surface water quality	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
2. Impacts of refurbishment on surface water use	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
3. Altered current patterns at intake and discharge structures	1	4 Introduction	4.2.1.2.1/4-5
4. Altered salinity gradients	1	4 Introduction	4.2.1.2.2/4-4
5. Altered thermal stratification of lakes	1	N/A	Issue applies to a plant feature, discharge to a lake, which DCPP does not have.
6. Temperature effects on sediment transport capacity	1	4 Introduction	4.2.1.2.3/4-8
7. Scouring caused by discharged cooling water	1	4 Introduction	4.2.1.2.3/4-6
8. Eutrophication	1	4 Introduction	4.2.1.2.3/4-9
9. Discharge of chlorine or other biocides	1	4 Introduction	4.2.1.2.4/4-10
10. Discharge of sanitary wastes and minor chemical spills	1	4 Introduction	4.2.1.2.4/4-10
11. Discharge of other metals in waste water	1	4 Introduction	4.2.1.2.4/4-10
12. Water use conflicts (plants with once-through cooling systems)	1	4 Introduction	4.2.1.3/4-13
13. Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	NA, and discussed in Section 4.1	Issue applies to a plant feature, cooling ponds or cooling towers, which DCPP does not have.

TABLE A-1

Issue[a]	Category	Section of this Environmental Report	GEIS Section/Page[b]
Aquatic Ecology (for all plants)			
14. Refurbishment impacts to aquatic resources	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
15. Accumulation of contaminants in sediments or biota	1	4 Introduction	4.2.1.2.4/4-10
16. Entrainment of phytoplankton and zooplankton	1	4 Introduction	4.2.2.1.1/4-15
17. Cold shock	1	4 Introduction	4.2.2.1.5/4-18
18. Thermal plume barrier to migrating fish	1	4 Introduction	4.2.2.1.6/4-19
19. Distribution of aquatic organisms	1	4 Introduction	4.2.2.1.6/4-19
20. Premature emergence of aquatic insects	1	4 Introduction	4.2.2.1.7/4-20
21. Gas supersaturation (gas bubble disease)	1	4 Introduction	4.2.2.1.8/4-21
22. Low dissolved oxygen in the discharge	1	4 Introduction	4.2.2.1.9/4-23
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4 Introduction	4.2.2.1.10/4-24
24. Stimulation of nuisance organisms (e.g., shipworms)	1	4 Introduction	4.2.2.1.10/4-25
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)			
25. Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	4.2	4.2.2.1.2/4-16

TABLE A-1

Issue[a]	Category	Section of this Environmental Report	GEIS Section/Page[b]
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	4.3	4.2.2.1.3/4-16
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	4.4	4.2.2.1.4/4-17
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)			
28. Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	N/A	Issue applies to a heat dissipation system, cooling towers, which DCPP does not have.
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	N/A	Issue applies to a heat dissipation system, cooling towers, which DCPP does not have.
30. Heat shock for plants with cooling tower-based heat dissipation systems	1	N/A	Issue applies to a heat dissipation system, cooling towers, which DCPP does not have.
Groundwater Use and Quality			
31. Impacts of refurbishment on groundwater use and quality	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
32. Groundwater use conflicts (potable and service water; plants that use <100 gpm)	1	4 Introduction	4.8.1.1/4-116 and 4.8.1.2/4-119
33. Groundwater use conflicts (potable, service water, and dewatering; plants that use >100 gpm)	2	NA, and discussed in Section 4.5	4.8.1.1/4-116 and 4.8.1.2/4-119
34. Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	NA, and discussed in Section 4.6	Issue applies to a plant feature, cooling towers, which DCPP does not have.

TABLE A-1

Issue[a]	Category	Section of this Environmental Report	GEIS Section/Page[b]
35. Groundwater use conflicts (Ranney wells)	2	NA, and discussed in Section 4.7	Issue applies to a plant with Ranney Wells, which DCPP does not have.
36. Groundwater quality degradation (Ranney wells)	1	N/A	Issue applies to a plant with Ranney Wells, which DCPP does not have.
37. Groundwater quality degradation (saltwater intrusion)	1	4 Introduction	4.8.2/4-118
38. Groundwater quality degradation (cooling ponds in salt marshes)	1	N/A	Issue applies to a feature, cooling ponds, which DCPP does not have.
39. Groundwater quality degradation (cooling ponds at inland sites)	2	NA, and discussed in Section 4.8	Issue applies to a feature, cooling ponds, which DCPP does not have.
Terrestrial Resources			
40. Refurbishment impacts to terrestrial resources	2	NA, and discussed in Section 4.9	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
41. Cooling tower impacts on crops and ornamental vegetation	1	N/A	Issue applies to a plant feature, cooling towers, which DCPP does not have.
42. Cooling tower impacts on native plants	1	N/A	Issue applies to a plant feature, cooling towers, which DCPP does not have.
43. Bird collisions with cooling towers	1	N/A	Issue applies to a plant feature, cooling towers, which DCPP does not have.
44. Cooling pond impacts on terrestrial resources	1	N/A	Issue applies to a feature, cooling ponds, which DCPP does not have.
45. Power line right-of-way management (cutting and herbicide application)	1	4 Introduction	4.5.6.1/4-71
46. Bird collisions with power lines	1	4 Introduction	4.5.6.2/4-74

TABLE A-1

Issue[a]	Category	Section of this Environmental Report	GEIS Section/Page[b]
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4 Introduction	4.5.6.34-77
48. Floodplains and wetlands on power line right-of-way	1	4 Introduction	4.5.7.7/4-81
Threatened or Endangered Species (for all plants)			
49. Threatened or endangered species	2	4.10	4.1/4-1
Air Quality			
50. Air quality during refurbishment (non-attainment and maintenance areas)	2	NA, and discussed in Section 4.11	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
51. Air quality effects of transmission lines	1	4 Introduction	4.5.2/4-62
Land Use			
52. Onsite land use	1	4 Introduction	3.2/3-1
53. Power line right-of-way land use impacts	1	4 Introduction	4.5.3/4-62
Human Health			
54. Radiation exposures to the public during refurbishment	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
55. Occupational radiation exposures during refurbishment	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
56. Microbiological organisms (occupational health)	1	4 Introduction	4.3.6/4-48
57. Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	NA, and discussed in Section 4.12	Issue applies to plant features, cooling lakes, canals or towers, which DCPP does not have.

TABLE A-1 Sheet 6 of 9

Issue[a]	Category	Section of this Environmental Report	GEIS Section/Page[b]
58. Noise	1	4 Introduction	4.3.7/4-49
59. Electromagnetic fields, acute effects	2	4.13	4.5.4.1/4-66
60. Electromagnetic fields, chronic effects	N/A	4 Introduction	
61. Radiation exposures to public (license renewal term)	1	4 Introduction	4.6.2/4-87
62. Occupational radiation exposures (license renewal term)	1	4 Introduction	4.6.3/4-95
Socioeconomics			
63. Housing impacts	2	4.14	3.7.2/3-10 (refurbishment - not applicable to DCPP) 4.7.1/4-101 (renewable term)
64. Public services: public safety, social services, and tourism and recreation	1	4 Introduction	Refurbishment (not applicable to DCPP because issue applies to an activity that DCPP does not plan to undertake) Renewal Term 4.7.3/4-104 (public safety) 4.7.3.3/4-106 (safety) 4.7.3.44-107 (social) 4.7.3.6/4-107 (tour, rec)
65. Public services: public utilities	2	4.15	3.7.4.5/3-19 (refurbishment - not applicable to DCPP) 4.7.3.5/4-107 (renewable term)
66. Public services: education (refurbishment)	2	NA, and discussed in Section 4.16	Issue applies to an activity, refurbishment, which DCPP does not plan to undertake.
67. Public services: education (license renewal term)	1	4 Introduction	4.7.3.1/4-106

TABLE A-1

Issue[a]	Category	Section of this Environmental Report	GEIS Section/Page[b]
68. Offsite land use (refurbishment)	2	NA, and discussed in Section 4.17.1	Issue applies to an activity, refurbishment, which DCPP does not plan to undertake.
69. Offsite land use (license renewal term)	2	4.17.2	4.7.4/4-107
70. Public services: transportation	2	4.18	3.7.4.2/3-17 (refurbishment - not applicable to DCPP) 4.7.3.2/4-106 (renewal term)
71. Historic and archaeological resources	2	4.19	3.7.7/3-23 (refurbishment - not applicable to DCPP) 4.7.7/4-114 (renewal term)
72. Aesthetic impacts (refurbishment)	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
73. Aesthetic impacts (license renewal term)	1	4 Introduction	4.7.6/4-111
74. Aesthetic impacts of transmission lines (license renewal term)	1	4 Introduction	4.5.8/4-83
Postulated Accidents			
75. Design basis accidents	1	4 Introduction	5.3.2/5-11 (design basis) 5.5.1/5-114 (summary)
76. Severe accidents	2	4.20	5.3.3/5-12 (probabilistic analysis) 5.3.3.2/5-19 (air dose) 5.3.3.3/5-49 (water) 5.3.3.4/5-65 (groundwater) 5.3.3.5/5-95 (economic) 5.4/5-106 (mitigation) 5.5.2/5-114 (summary)
Uranium Fuel Cycle and Waste Management			
77. Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	1	4 Introduction	6.2/6-8

TABLE A-1

Issue[a]	Category	Section of this Environmental Report	GEIS Section/Page[b]
78. Offsite radiological impacts (collective effects)	1	4 Introduction	Not in GEIS.
79. Offsite radiological impacts (spent fuel and high-level waste disposal)	1	4 Introduction	Not in GEIS.
80. Nonradiological impacts of the uranium fuel cycle	1	4 Introduction	6.2.2.6/6-20 (land use) 6.2.2.7/6-20 (water use) 6.2.2.8/6-21 (fossil fuel) 6.2.2.9/6-21 (chemical)
81. Low-level waste storage and disposal	1	4 Introduction	6.4.2/6-36 (low-level def) 6.4.3/6-37 (low-level volume) 6.4.4/6-48 (renewal effects)
82. Mixed waste storage and disposal	1	4 Introduction	6.4.5/6-63
83. Onsite spent fuel	1	4 Introduction	6.4.6/6-70
84. Nonradiological waste	1	4 Introduction	6.5/6-86
85. Transportation	1	4 Introduction	6.3/6-31, as revised by Addendum 1, August 1999.
Decommissioning			
86. Radiation doses (decommissioning)	1	4 Introduction	7.3.1/7-15
87. Waste management (decommissioning)	1	4 Introduction	7.3.2/7-19 (impacts) 7.4/7-25 (conclusions)
88. Air quality (decommissioning)	1	4 Introduction	7.3.3/7-21 (air) 7.4/7-25 (conclusions)
89. Water quality (decommissioning)	1	4 Introduction	7.3.4/7-21 (water) 7.4/7-25 (conclusions)
90. Ecological resources (decommissioning)	1	4 Introduction	7.3.5/7-21 (ecological) 7.4/7-25 (conclusions)
91. Socioeconomic impacts (decommissioning)	1	4 Introduction	7.3.7/7-19 (socioeconomic) 7.4/7-24 (conclusions)

TABLE A-1

Issue[a]	**Category**	**Section of this Environmental Report**	**GEIS Section/Page**[b]
Environmental Justice			
92. Environmental justice	N/A	2.6.2	

a. Source: 10 CFR 51, Subpart A, Appendix A, Table B-1. (Issue numbers added to facilitate discussion.)
b. Source: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437).

ATTACHMENT B – NPDES PERMIT

ID#3 402003001

CALIFORNIA REGIONAL WATER QUALITY CONTROL BOARD
CENTRAL COAST REGION
1102-A Laurel Lane
San Luis Obispo, California 93401

ORDER NO. 90-09
NPDES NO. CA0003751

WASTE DISCHARGE REQUIREMENTS
FOR
PACIFIC GAS AND ELECTRIC COMPANY
DIABLO CANYON NUCLEAR POWER PLANT
UNITS 1 AND 2
SAN LUIS OBISPO COUNTY

The California Regional Water Quality Control Board, Central Coast Region (hereafter Board), finds:

1. Pacific Gas and Electric Company, with headquarters at 77 Beale Street, San Francisco, CA 94106 (hereafter Discharger) owns and operates a nuclear power plant located approximately 12 miles southwest of San Luis Obispo (35°12'44" N Latitude, 120°51'14" W Longitude) an shown on Attachments "A" and "B". The power plant consists of two generating units, with a net power generating capacity of 2269 MW

2. The Diablo Canyon Nuclear Power Plant discharges up to 2,540 MGD of seawater for main condenser cooling. Smaller amounts of in-plant chemical wastes, low-level radioactive waste and stormwater runoff are also discharged. The cooling water intake is located in the Intake Cove south of the plant, and the cooling water discharge is into Diablo Cove (Discharge 001), southwest of the plant. Intake structure floor drains (Discharge 002) discharge into the Intake Cove west of the cooling water intakes. Intake screen wash (Discharge 003) is discharged into the ocean on the west breakwater. The Biolab and Yard Storm Drain (Discharge 004) discharge to the Intake Cove east of the intake structure. Yard Storm Drain (Discharge 005) and Stormwater (Discharges 006 and 007) are discharged into the ocean at three points downcoast of the Intake Cove. The Biolab Seawater Supply Pump Valve Drain (016) and the Seawater Reverse Osmosis System Blowdown Drain (017) both discharge into the Intake Cove east of the intake structure. Stormwater and yard drainage are also discharged to Diablo Creek (Discharges 008, 009, 010, 011, 012, 013, 014 and 015.)

3. An application for re-authorization to discharge wastes under the National Pollutant Discharge Elimination System (NPDES) was submitted to the Board on November 15, 1989, and supplemented by information on February 22, 1990. NPDES Permit No. CA0003751 was last issued by the Board on July 12, 1985.

WDR Order No. 90-09

4. Waste discharges, as located on Attachment “B” and shown schematically on Attachment “C” of this Order, are described as follow:

Discharge 001 - Once-Through Cooling Water.

Design Flow: 2,540 MGD with two units operating. Cooling water for steam condensers and service cooling systems, and in-plant waste streams, is discharged to Diablo Cove. Natura1 temperatures of water in both coves are assumed comparable at any time. Discharge of corrosion inhibitors used in closed cooling water systems can occur due to leakage, or during operation, testing and maintenance activities.

Service cooling water systems and in-plant waste streams, discharging to the once-through cooling water system are as follows:

Discharge 001 A, (1), (2) and (3) Firewater System.

This discharge description has been deleted and those discharges which receive firewater-see-note l) from the firewater system are identified in the following discharge descriptions. The periodic testing and flushing of the firewater system are also described.

Discharge 001 B, Auxiliary Salt Water Cooling System, 6.34×10^7 GPD .

This system provides once-through cooling water for the component cooling water system (a closed cooling water loop servicing pumps and other loads in the electric generation system). Discharge of chromate/potassium hydroxide based or molybdate/tolytriazole based corrosion inhibitors, used in closed cooling water systems, may occur due to leakage or during operation, testing and maintenance activities.

Part of the auxiliary salt water system may be taken out of service and filled with firewater to control biofouling. When the system is returned to service, approximately 40,000 gallons of firewater will be discharged. Periodic flowrate testing of this system is performed using a dye, such as rhodamine. The Discharger will provide prior notification to the Board staff.

Discharge No. 001C-Discharge deleted.

Discharge 001 D, Liquid Radioactive Waste Treatment System Effluent, 5×10^4 GPD, (Intermittent).

Liquid Radioactive Waste (LRW) from reactor systems is collected, treated and monitored in a LRW treatment system. This system includes storage tanks for radioactive decay, evaporators, activated carbon filters, ion exchangers, and filters to remove radioactive matter. Small amounts of sodium hydroxide, sulfuric acid, and polyelectrolyte may be used as treatment aids. Solid wastes produced by ion-exchange resins and filter media are collected and packaged for off-site disposal. After decay and/or treatment, individual batches of low-level waste are sampled and analyzed to confirm compliance with discharge limits, passed through a 5 micron filter, and discharged into the auxiliary salt water cooling system (Discharge 001B). Wastes from other plant systems collected in the

LRW treatment system from leakage, or operation, maintenance and testing activities could contain boric acid, lithium hydroxide, sulfuric acid, ammonium hydroxide or other neutralizing amines, hydrazine, sodium sulfate, chemicals from primary laboratory drains, hot shower and laundry wastes, metal cleaning wastes, chromate/potassium hydroxide based or molybdate/tolytriazole based corrosion inhibitors, and firewater system flush water (see note 1).

Discharge 001E, Service Cooling Water System, 2.5 x 10^7 GPD.

This system provides once-through-cooling water for the Service Cooling Water System (a closed cooling water loop servicing pumps and other loads in the electric generation system). Discharge of chromate/potassium hydroxide based or molybdate/tolytriazole based corrosion inhibitors may occur due to leakage or during operation testing and maintenance activities.

Discharge 001 F, Turbine Building Sump, 1.5 x 10^5 GPD, (Intermittent).

Floor drainage from the turbine building, buttress areas, other sumps, secondary systems, secondary systems chemistry laboratories, and firewater system flush (see note 1), are collected in the turbine building sump. Discharge may contain boric acid, sodium hydroxide, sulfuric acid, chromate/potassium hydroxide based or molybdate/tolytriazole based corrosion inhibitors, chemicals from the secondary chemistry laboratory drains, hydrazine, ammonium hydroxide or other neutralizing amines. The turbine building sump effluent is treated in an oily water separator or the Wastewater Holding and Treatment (WHAT) system prior to discharge to the main circulating water. Polyelectrolytes may be used as a treatment aid.

Discharge 001 G, Make-Up Water System Waste Effluent, 4.83 x 10^3 GPD.

Filter backwashes from make-up water pretreatment and treatment systems, and blowdown from the reverse osmosis Systems are discharged to the main circulating water. This waste contains filter backwash, concentrated dissolved solids, and water treatment chemicals such as: sulfuric acid, sequestering agents, sodium hypochlorite, sodium hydroxide and sodium bisulfite.

Discharge 001 H, Condensate Demineralizer Regenerant, 1.5 x 10^3 GPD, (Intermittent).

Waste regenerant solution from the steam-cycle condensate demineralizers is collected in regenerant waste tanks for neutralization, filtration and discharged to the main circulating water. The principal discharge constituent is sodium sulfate. It may also include hydrazine, boric acid, ammonia or other neutralizing amines and corrosion products.

Discharge 001 I, Seawater Evaporator Blowdown, 5.0 x 10^5 GPD.

Seawater is concentrated in the seawater evaporation system and discharged. The effluent has a two-fold increase in salinity. Water treatment chemicals such as sulfuric acid and polymer are added to control scaling.

Discharge 001 J, Condensate Pumps Discharge Header Overboard, 3.6 x 10^3 GPD, (Intermittent).

During normal start-up operations, and occasionally during power operations, condensate from the main condenser hot well will be periodically discharged to improve condensate quality in the steam cycle. The discharge is demineralized water containing ammonium hydroxide or other neutralizing amines, hydrazine, boric acid, and impurities such as corrosion products and seawater which may result from condenser leakage.

Discharge 001 K, Condenser Tube Sheet Leak Detection Dump Tank Overboard, 1.4 s 10^5 GPD, (Intermittent).

Water from the main condenser tube sheet collection trough will be discharged periodically in order to minimize seawater contamination of the condensate during periods of condenser tube sheet leakage. This discharge is demineralized water containing ammonium hydroxide or other neutralizing amines, hydrazine, boric acid, and impurities such as corrosion products and seawater which may result from condenser leakage.

Discharge 001 L, Steam Generator Blowdown, 6.5 x 10^5 GPD.

This normally continuous discharge contains corrosion products and seawater contaminants from condenser tube leakage. Treatment chemicals include boric acid, ammonium hydroxide or other neutralizing amines, and hydrazine.

Discharge 001 M, Wastewater Holding and Treatment System, 8 x 10^5 GPD. (Intermittent).

Water routed to the WHAT system will be periodically discharged. This discharge includes wastes from discharges 001F and 001H requiring further treatment. Treatment may involve coagulation, settling, oil removal, neutralization, filtration, or chlorination. (See note 1 for firewater discharge.)

Discharge 001 N. Sanitary Wastewater Treatment System, 3.5 x 10^3 GPD.

Sanitary waste is treated in a package treatment facility, with the normal discharge to the Unit 2 cooling water discharge (001). In the event both discharge pumps fail, an alternate discharge path is gravity overflowed to the seawater reverse osmosis system discharge (001 p). During a discharge to 001 P. a portion of the effluent could be discharged along with the intake screen wash water (003). Chlorine is periodically used in this system to control filamentous growth. In the event the treatment facility is inoperable, sanitary waste will receive treatment in septic tanks and be discharged to leachfields.

Discharge 001 P, Seawater Reverse Osmosis System Blowdown, 1.44 x 10^6 GPD.

Blowdown from the seawater reverse osmosis system contains concentrated seawater brine and filter backwash, with additions of water treatment chemicals such as sulfuric acid, ferric sulfate, a sequestering agent, sodium hypochlorite and sodium bisulfite. Blowdown is normally discharged through the intake structure to the auxiliary salt water system. When auxiliary salt water system pumps are not operating, an alternate discharge path is to the intake screen wash (003). Treated domestic sanitary wastes (001 N) are discharged to the seawater reverse osmosis system slowdown, in the event of a failure of both discharge pumps.

Discharge 002, Intake Structure Building Floor Drains, 3.5 x 10^3 GPD, (Intermittent).
Drainage from within the cooling water intake structure and firewater system flush (see note 1), is collected in sumps and discharged inside the breakwater adjacent to the intake structure. Discharge of chromate/potassium hydroxide based or molybdate/tolytriazole based corrosion inhibitors may be present in this discharge due to leakage or during operation, treating and maintenance activities.

Discharge 003, Intake Screen Wash, 5.76 x 10^6 GPD.
Solid material from the ocean is washed from traveling screens at the intake structure, collected in a collection pit, and removed for land disposal. The screen wash water and the materia1 passing through the collection pit screen are pumped back to the ocean at point located on the ocean side of the breakwater. This system may contain hypochlorite during periods of circulating water chlorination. During heat treatment of main condensers, some heated seawater is discharged at this point. The seawater reverse osmosis blowdown can also discharge at this point when the auxiliary salt water system pumps are not operating.

Discharge 004, Biolab Discharge, 1.73 x 10^6 GPD, and Yard Storm Drain, Flow Variable.
This discharge normally consists of the seawater discharge from the Biolab, (formerly called the Thermal Effects Lab). Seawater is pumped from the intake structure to tanks used for observation and scientific study of marine organisms, and discharged continuously to the intake cove. Approximately one-half of the seawater supplied to the Biolab is filtered through sand filters at line pressure. Filters are backwashed based on pressure differentials and the filtrate (debris from the ocean) is discharged through discharge 004. This system may be filled with freshwater as a method of biofouling control. It may also contain trace amounts of hypochlorite and/or other oxidants from future biofouling control optimization studies. Storm water from a portion of the plant yard area is collected in a drainage system that occasionally includes firewater (see note 1), washwater, and stored water releases. This drainage system includes a 17,000 gallon sump which serves as a collection system for the Spill Prevention Control and Countermeasure (SPCC) Plan. This sump has a passive oil-water separation system for the containment of transformer oil. The discharge also includes drainage for areas surrounding the hazardous waste storage building, truck bay, firewater storage tank and firewater pump building. Drainage joins the Biolab discharge before entering the intake cove.

Discharge 005, Yard Storm Drains, Flow Variable.
Storm water runoff from the plant yard on the Unit 2 side of the radwaste buildings and the west side of the turbine buildings is discharged to South Cove. This may occasionally include some firewater (see note 1), washwater and stored water releases. Rain water and washwater from the rotor warehouse and

adjacent areas is collected in a sump and routed into this drainage system.

Discharge 006, Storm Water Runoff, Flow Variable.
Storm water runoff from the Pacific Ocean side of the ridge to the southeast of the plant is discharged to South Cove. Storm water runoff from the south warehouse, the shooting range, and a temporary parking lot also drains to this discharge.

Discharge 007, Storm Water Runoff, Flow Variable.
Storm water runoff from an area to the south of the same ridge that drains to Discharge 006 is routed to the ocean near the southern site boundary. Drainage from the general construction paint department, the temporary hazardous waste storage area, the diked gasoline and fuel oil tanks area and the sails lab are routed to this discharge.

Discharge 008, Yard Storm Drain, Flow Variable; Storm Water Runoff, Flow Variable .
Storm water runoff from the yard area on the northwest side of the turbine building is drained to the west plant access road and discharged into Diablo Creek. This discharge may occasionally include some firewater (see note 1), washwater and stored water releases. Storm water runoff from watershed areas north of Diablo Creek is collected in a second drainage system and discharged to Diablo Creek at the same point.

Discharge 009, Yard Storm Drain, Flow Variable.
Storm water runoff from the north and northeast side of the Unit 1 auxiliary, containment, fuel handling and turbine buildings, and the protected area hazardous waste storage facility, drains to the north side of the plant yard and discharges to Diablo Creek. This discharge may occasionally include firewater (see note 1), washwater and stored water releases. This drainage system includes a 17,000 gallon sump which serves as a collection system for the Spill Prevention Control and Countermeasure (SPCC) Plan. The sump has a passive oil-water separation system provided for containment of any spill of oil from a main transformer. (The protected area hazardous waste storage facility is a concrete diked enclosure surrounded by a locked chain-link fence.)

Discharge 010, Storm Water Runoff, Flow Variable.
Storm water runoff from the hillside between the plant and the raw water reservoirs drains into a concrete culvert and is routed to the north along the hillside and discharged to Diablo Creek. This discharge may occasionally include firewater (see note 1), washwater and stored water releases.

Discharge 011, Storm Water Runoff, Flow Variable.
Storm water runoff from watershed areas north of Diablo Creek drains to the north switchyard access road and discharges to Diablo Creek.

Discharge 012, Storm Hater Runoff, Flow variable.
Storm water runoff from the watershed area between the 230 KV switchyard and the 500 KV switchyard drains to a vertical shaft leading to the Diablo Creek

culvert passing under the switchyard.

Discharge 013, Yard Storm Drain, Flow Variable.
Storm water from the raw water reservoirs, the make-up water treatment area, and the 230 KV switchyard collect in a drainage system and is routed to Diablo Creek. Some runoff from the hillside under the 500 KV power lines is also included in this drainage. This drainage may occasionally include firewater (see note 1), washwater and stored water releases.

Discharge 014, Yard Storm Drains, Flow Variable.
Storm water runoff from laydown areas, dog kennels, and the hillside south and east of the 500 KV switchyard collected in a drainage ditch and routed to Diablo Creek.

Discharge 015, Yard Store Drain, Flow Variable.
Storm water runoff from the area around the temporary auto facility, carwash slab, and adjacent roadway; as wash water from the carwash slab, is collected in a sump with an oil water separator, and then routed to Diablo Creek.

Discharge 016, Biolab Seawater Supply Pump Valve Drain, Flow Variable.
A drain is provided in the seawater supply valve box for removal of accumulated rainwater and seawater. Discharge is to South Cove.

Discharge 017, Seawater Reverse Osmosis System Blowdown Drain, Flow Variable.
A low-point valve located beside the Intake Structure access road allows the 8” brine line to be drained for repair. Only rare use of the drain during the lifetime of the system is expected. The discharge is to South Cove.

Note 1: The firewater system is periodically flushed, tested, and diverted as described below:

1. Firewater System Flush, 5.0×10^4 GPD, (Intermittent).
Firewater will be discharged semiannually when portions of the system are flushed to ensure they remain clear. The discharges are to yard storm drains, building floor drains and the LRW treatment system (discharge 001D).

2. Firewater System Flow Test, 2.4×10^4 GPD, (intermittent).
This test is conducted once every three years to comply with Nuclear Regulatory Commission requirements. The discharges are to yard storm drains, building floor drains and the LRW treatment system (discharge 001D).

3. Fire Hose Test, 1.4 s 10^3 GPD, (Intermittent).
This test is conducted annually on portions of the firewater system to comply with Nuclear Regulatory Commission requirements. The discharges are to yard storm drains and building floor drains and the LRW treatment system (discharge 001D). (Unscheduled

discharges from firewater systems will occur in the event of fire and on occasion from washing.)

The firewater system may contain a corrosion inhibitor and/or a biocide for corrosion and/or scale protection.

5. The Environmental Protection Agency and Board have classified this discharge as a major discharge.

6. The Water Quality Control Plan, Central Coastal Basin (Basin Plan) was adopted by the Board on March 14, 1975 and approved by the State Board on March 30, 1975. The Basin Plan incorporates State Board plans and policies by reference and contains a strategy for protecting beneficia1 uses of the Pacific Ocean.

7. Existing and anticipated beneficial uses in the vicinity of the discharge Include:

   a. Water contact recreation;
   b. Non-contact water recreation, including aesthetic enjoyment;
   c. Industrial water supply;
   d. Navigation;
   e. Marine habitat;
   f. Shell fish harvesting;
   g. Preservation of Rare and Endangered Species;
   h. Wildlife habitat; and,
   i. Ocean commercial and sport fishing.

8. The State Board adopted the “Water Quality Control Plan, Ocean Waters of California, California Ocean Plan” (Ocean Plan) or September 22, 1988. The Ocean Plan contains water quality objectives and other requirements governing discharge to the Pacific Ocean. On March 4, 1989, the Discharger submitted report ”Estimation of the Dilution Factor for the Diablo Canyon Power Plant Thermal Discharge Plume”, as required by Monitoring and Reporting Program No. 85-101. This report concluded the minimum initial dilution of the discharge 4.1:1 (seawater: effluent). This ratio as used for calculating effluent limits based on Ocean Plan water quality standards. The minimum initial dilution previously used as 6.4:1.

9. The State Board adopted a revised Ocean Plan on March 22, 1990. The revised Plan was adopted too late to be included in this NPDES Permit. Provision No.D.7. requires the discharger to submit a report evaluating its ability to comply with the revised Ocean Plan and to prepare an implementation schedule, if needed, for achieving full compliance. The Board will consider revising the Permit after receipt and review of the report.

10. The State Board adopted the "Water Quality Control Plan for Control of Temperature in the Coastal and Interstate Water and Enclosed Bays and Estuaries of California” (Thermal Plan) on September 18, 1975. This plan contains water quality objectives for the Pacific Ocean in the area of Diablo Canyon Units 1 and 2 at Diablo Canyon are classified as existing

discharges in the Thermal Plan. This classification requires the Regional Board to establish limits to assure protection of beneficial uses. The Thermal Plan requires existing dischargers to define the effect of their discharges on beneficial uses and determine, as necessary, design and operating changes necessary to achieve compliance.

11. Effluent limitations and toxic and effluent standards established pursuant to Sections 301, 302, 303(d), 304, 307 and 316 of the Clean Water Act (CWA) and Amendments thereto are applicable to the discharge. Final regulations defining effluent limitation guidelines for the steam-electric industry were promulgated by EPA on November 19, 1982.

12. Temperature of cooling water is raised approximately 20 degrees F during commercial operation. The cooling water temperature increase may be greater than 20 degrees F during condenser heat treatment or transient conditions. Transient conditions can include load rejection, steam dump, generator trip, and conditions resulting from operation of engineered safety features, as well as periods of reduced flow resulting from condenser tube sheet plugging, condenser fouling, or loss of a circulating water pump. Periodic thermal treatment of each cooling water system is necessary to demuseel and minimize the growth of marine organisms in the piping and heat exchangers. The frequency of this operation will vary seasonally but is expected to average once per month for each condenser. Thermal treatment of each half-condenser takes nine hours with the maximum temperature being maintained for one hour.

13. Thermal effects on the receiving water, actua1 temperature increases, and actual temperatures of the discharge are monitored end results correlated and evaluated as part of ongoing studies. These studies are being performed as required in Monitoring and Reporting Program No. 90-09. This monitoring is developed and reviewed jointly by Board and Department of Fish and Game staff. The results of the studies may result in more stringent thermal limits.

14. Section 316 (b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the Best Technology Available (BTA) for minimizing adverse environmenta1 impact. An April 28, 1988, study of the cooling water intake structure was submitted which concluded the facilities at Diablo Canyon Power Plant reflect BTA.

15. Waste discharge requirements for this discharge are exempt from the provisions of the California Environmental Quality Act (Public Resources Code. Section. 21100 et seq.) in accordance with Section 13389 of the California Water Code.

16. A permit and the privilege to discharge waste into waters of the State is conditional upon the discharge complying with provisions of Division 7 of the California Water Code and of the Clean Water Act (as amended or as supplemented by implementing guidelines and regulations) and with any more stringent effluent limitations necessary to implement water quality control plans, to protect beneficial

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uses, and to prevent nuisance. This Order shall serve as a National Pollutant Discharge Elimination System Permit pursuant to Section 402 of the Clean Water Act. Compliance with this Order should assure conditions are met and mitigate any potential changes in water quality due to the project.

17. On March 20, 1990, the Board notified the Discharger and interested persons of its intent to reissue waste discharge requirement for the discharge, provided them with an opportunity to submit their written views and recommendations, and scheduled a public hearing.

18. In a public hearing on May 11, 1990, the Board heard and considered all comments pertaining to the discharge and found this Order consistent with the above findings.

IT IS HEREBY ORDERED, pursuant to authority In Section 13377 of the California Water Code, Pacific Gas & Electric Company, its agents, successors, and assigns, may discharge waste from the Diablo Canyon Power Plant providing they comply with the following:

(General permit conditions, definitions and the method of determining compliance are contained in the attached “Standard Provisions and Reporting Requirements for National Pollutant Discharge Elimination System Permits,” dated January, 1985. Applicable paragraphs are referenced in Provision D.3. of this Order.)

A. Discharge Prohibitions

1. Any discharge at a location other than as described in the permit application, Finding No. 4, or shown on Attachment “B” or “C”, is prohibited. This prohibition does not apply to storm runoff.

2. The discharge of polychlorinated biphenyl compounds is prohibited.
3. Except as described In Finding No. 4, discharge of sludges, centrates, screenings, backwashes, or filtrates to surface waters is prohibited.

4. Discharge of nonhazardous solid waste, (as defined In California Code of Regulations, Title 23, Chapter 3, Subchapter 15, Section 2523(a), adopted December 8, 1984), to surface waters is prohibited.

5. Discharge of untreated or partially treated sanitary wastes and discharge of septic tank effluent to the Pacific Ocean or its tributaries, is prohibited.

B. Effluent Limitations

1. Discharge 001

a. Discharge shall not exceed 2760 MGD.

b. Effluent shall not exceed the following limits:*

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Constituents	Units	Concentrations 6-Month Median	Daily Max	Instan-taneous Maximum
Arsenic	ug/l	30.	150.	400.
Cadmium	ug/l	10.	20.	50.
Chromium (Hex)**	ug/l	10.	40.	100.
Copper	ug/l	10.	50.	140.
Lead	ug/l	10.	40.	100.
Mercury	ug/l	0.2	0.8	2.
Nickel	ug/l	30.	100.	260.
Silver	ug/l	2.9	13.6	35.
Zinc	ug/l	70.	380.	990.
Cyanide	ug/l	30.	100.	260.
Total Residual Chlorine (TRC)***	ug/l			200.
Ammonia (as N)	ug/l	3060.	12240.	30600.
Toxicity Concentration	tu	0.26	-	-
Phenolic Compounds (non-chlorinated)	ug/l	150.	610.	1530.
Chlorinated Phenolics	ug/l	10.	20.	50.

Constituents	Units	Concentrations 6-Month Median	Daily Max	Instan-taneous Maximum
Radioactivity	Not to exceed limits specified in Title 17, Chapter 5, Subchapter 4, Group 3, Article 3, Section 30269 of the California Code of Regulations .			

* Based on Ocean Plan criteria using a minimum initial dilution of 4.1:1. If actual dilution is found to be less then this value, fit will be recalculated and the order revised.

** The chromium limit may be met as total chromium if the Discharger chooses.

.*** TRC may not be discharged from any single generating unit for more than two hours per day. At least thirty minutes must separate the chlorine discharge from each one-half condenser unit.

c. During any 24-hour period, the effluent mass emission rate shall not exceed the Maximum Daily Mass Emission Rate".

d. Violation of the "Instantaneous Maximum" or "Maximum Allowable Daily Mass

Emission Rate" must be reported to the Board within 24 hours.

e. During any six-month period, the effluent mass emission rate shall not exceed the "Maximum Allowable Six-Month Median Mass Emission Rate."

f. The daily average discharge temperature shall not exceed the daily average of the natural temperature of the Intake water by more then 22 degrees F (12.2 degrees C), except during heat treatment.

g. During heat treatment for demusseling, the daily average discharge temperature shall not exceed the daily average of the natural temperature of the intake water by more than 25 degrees F (13.9 degrees C), and the maximum temperature increase (delta T) measured at the point of discharge of the unit being treated shall be lets than 5O degrees F (27.8 degrees C) over that of the intake. The duration of maximum temperature during heat treatment of any half-condenser shall not exceed one hour during any 24 hour period. Pumps for the unit not being treated should be operated during demusseling.

2. <u>Discharge 00lD, 00lF, 0OlG. 00lH. DO1I, 00lJ, 00lK, 00lL, 001M, 00lP, AND 002</u>:

Effluent concentrations shall not exceed the following limits:

Constituent	Units	Monthly Average	Daily Maximum
Suspended Solids	mg/l	30	100
Grease and oil	mg/l	15	20

3. <u>Discharge 001D, 001F, 001I, 001L, and 001M:</u>

When metal cleaning operations occur on these waste streams, effluent concentrations shall not exceed the following limits:

Constituent	Units	Daily Maximum
Copper, total	mg/l	1.0
Iron, total	mg/l	1.0

4. Discharge 001N:

Effluent concentrations shall not exceed the following limits:

Constituent	Units	Monthly (30-day Avg.)	Maximum
Grease & Oil	mg/l	15	20
Settleable Solids	ml/l	1.0	3.0
Suspended Solids	mg/l	60	

5. Discharge 002, 003, 004, 005, 008, 009, 013, 014, 015, 016, and 017:

Effluent discharged shall not violate water quality objectives contained in Chapter II, General Requirements contained in Chapter III, nor Table B Toxic Materials Limitations contained in Chapter IV of the Water Quality Control Plan for Ocean Waters of California, California Ocean Plan.

6. Discharge 003, 004, 005, 008, 009, 013, 015, 016, and 017:

Effluent concentrations shall not exceed a Monthly Average Grease and Oil limit of 15 mg/1 and a Daily Maximum of 20 mg/1.

C. Receiving Water Limitations

(Receiving water quality is a result of many factors, some unrelated to the discharge. This permit considers these other factors, and is designed to minimize the adverse influence of the discharge in the receiving water).

Waste discharges shall not individually or collectively cause

1. Floating particulates and grease and oil to be visible on the water surface.

2. Aesthetically undesirable discoloration of the water surface.

3. Significant reduction in transmittance of natural light in ocean waters which may cause marine communities to be degraded.

4. Change in the rate of deposition of inert solids and the characteristics of inert solids in sediments such that benthic communities are degraded.

5. The dissolved oxygen concentration to fall below 5.0 mg/l or to be depressed more than 10 percent from that which occurs naturally.

6. The pH to be depressed below 7.0, raised above 8.5, or changed more than 0.2 units from that which occurs naturally.

7. Dissolved sulfide concentrations of waters in and near sediments to increase

significantly above those present under natural conditions.

8. Concentrations of the same substances listed in Effluent Limitation No. B.1.b. to increase in marine sediments to levels which would degrade the indigenous biota.

9. Objectionable aquatic growth or degradation of indigenous biota.

10. Concentrations of organic materials in marine sediments to increase to a level which would degrade marine life.

11. Degradation of marine communities, including vertebrate, invertebrate, and plant species.

12. Alteration in natural taste, odor, and color of fish, shellfish, or other marine resources used for human consumption.

13. Degradation of marine life due to radioactive waste.

14. Temperature of the receiving water to adversely affect beneficial uses.

15. The following bacteriological limits to be exceeded in the water column (a) within a zone bounded by the shoreline and either the 30-foot depth contour or a distance of 1,000 feet from the shoreline, whichever is greater; and (b) within areas used for body contact recreation:

Parameter Appliance to any 30-Day Period	Total Coliform Organisms (MPN/100 ml)	Fecal Coliform Organisms (MPN/100 ml)
Log Mean	- - -	200
90% of Samples	- - -	400
80% of Samples	1,000	- - -
*Maximum	10,000	- - -

*Verified by a repeat sample taken within 48 hours.

16. The following bacteriological limits to be exceeded in the water column of areas where shellfish are harvested:

Parameter Applicable To any 30-Day Period	Total Coliform Organisms (MPN/100ml)
Median	70
90% of Samples	230

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D. Provisions

1. Requirements prescribed by this Order supersede requirements prescribed by Amended Order No. 85-101 adopted by the Board on July 12, 1985. Order No. 85-101 is hereby rescinded.

2. Discharger shall comply with “Monitoring and Reporting Program No. 90-09” specified by the Executive Officer.

3. The discharger shall comply with Items A.2. –A.5, A.8. –A.12, A.14. –A.23., B.1-B.7., C.1. –C.8., C.10. –C.15., C-18., E.1. and 2., and F.1. –F.6., of the “Standard Provisions and Reporting Requirements for National Pollutant Discharge Elimination System Permits,” date January, 1985. Paragraph (a) of Item E.1 shall apply only if the bypass is for essential maintenance to assure efficient operation. Bypasses authorized under paragraph (a) of Item E.1. are not subject to paragraphs (b) and (c) of Item E.1.

4. Discharge of any wastes of significantly different character than described in the Permit Application Finding No. 4., or as shown on Attachment “C”, shall be reported to the Executive Officer within five (5) days of knowing of such a discharge.

5. Plant operations shall at all times include the recommendations and procedures of the Best Management Practices Plan. The Plan may be amended as approved by the Executive Officer.

6. Rerouting of in-plant waste streams identified in Finding No. 4 or shown on Attachment “C” may be made with concurrence of the Executive Officer.

7. Discharger shall comply with the Water Quality Control Plan, Ocean Waters of California, California Ocean Plan adopted March 22, 1990, (1990 Ocean Plan) and corrections thereto. Compliance with those elements of the 1990 Ocean Plan different than the 1988 Ocean Plan shall be achieved according to the following schedule:

    a. Submit an Engineering Report by November 12, 1990 addressing the Discharger’s ability to comply with the 1990 Ocean Plan and including a time schedule for bringing the discharge into full compliance with the Ocean Plan changes.

    b. By November 12, 1990, comply with those elements of the 1990 Ocean Plan for which the Diablo Canyon Nuclear Power Plant is in compliance, or can achieve compliance without requiring: a change in the Power Plant operations; a modification to the Power Plant; or, the addition of treatment facilities

    c. Comply by dates to be determined by the Regional Board with those elements of the 1990 Ocean Plan for which the Diablo Canyon Nuclear Power Plant is not achieving compliance on November 12, 1990.

8. Any studies performed at the Biolab which may affect the nature of Discharge No. 004, shall not commence until a study plan is submitted and approved by the Executive Officer. The study plan shall include a listing of chemical additions which may be discharged.

9. This Order expires July 1, l995. The discharger must file a report of waste discharge in accordance with Title 23, Chapter 3, Subchapter 9 of the California Code of Regulations, not later than 180 days in advance of such expiration date as application for issuance of new waste discharge requirements.

I, WILLIAM R. LEONARD, Executive Officer, do hereby certify the foregoing is a full, true, and correct copy of an Order adopted by the California Regional Water Quality Control Board, Central Coast Region, on May 11, 1990.

Executive Officer

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STATE OF CALIFORNIA

PETE WILSON, *Governor*

CALIFORNIA REGIONAL WATER QUALITY CONTROL BOARD —
CENTRAL COAST REGION
UERA STREET, SUITE 200
LUIS OBISPO, CA 93401-5414
(805) 549-3147

Shawn Laforce

Diablo Canyon
Vice President &
Plant Manager

JUL 3 1995

Copy To: Drew Squyres

June 26, 1995

Warren Fujimoto, Plant Manager
Diablo Canyon Power Plant
Pacific Gas and Electric Company
P. O. Box 56
Avila Beach, CA 93424

Dear Mr. Fujimoto:

PG&E DIABLO CANYON, CONTINUATION OF NPDES PERMIT NO. CA0003751

We have received a timely and complete application for reissuance of NPDES Permit No. CA0003751, which expires on July 1, 1995. However, the current multiagency workshop process may result in findings which should be considered by the Regional Board in the reissued permit.

Therefore, pursuant to authority in 40 CFR Part 122.6, you are hereby notified that, conditional upon payment of the appropriate annual fees and compliance with the terms and conditions of this permit, NPDES Permit No. CA0003751 is continued and the permit will be in force, fully effective and enforceable until January 1, 1997.

If you have questions, please contact Sorrel Marks (549-3695) or Brad Hagemann (549-3697) of my staff.

Sincerely,

Bradley E. Hagemann

FOR Roger W. Briggs
Executive Officer

SJM/W:diablo.ext

STATE OF CALIFORNIA - ENVIRONMENTAL PROTECTION AGENCY PETE WILSON, *Governor*

CALIFORNIA REGIONAL WATER QUALITY CONTROL BOARD
CENTRAL COAST REGION
HIGUERA STREET, SUITE 200
SAN LUIS OBISPO, CALIFORNIA 93401-5427
(805)549-3147

Fax:(805)543-0397

August 29, 1996

Mr. Jeff Hays, Director, Chemistry and Environment
Pacific Gas and Electric company
Diablo Canyon Power Plant
P.O. Box 56
Avila Beach, CA 93424

Dear Mr. Hays:

Mr. Pat Mullen called me with questions regarding the renewal of your discharge permit. As you know, the Regional Board is interested in workgroup progress prior to taking up the permit again. Our regulations (Title 23, Section 2235.4) allow your permit to remain valid until the new permit is issued as long as you comply with requirements. This statement does not preclude the Regional Board from exercising its authority to request additional information.

If you have any questions, please call me at 549-3140.

Sincerely,

Roger W. Briggs
Executive Officer

c: Pat Mullen, PG&E

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ATTACHMENT C – AGENCY CORRESPONDENCE

Pacific Gas and *Electric Company*

M. Fry
Sr. Consulting Scientist
Environmental Services

Mailing Address
3401 Crow Canyon Rd.
San Ramon, Ca 94583
Tel: 925-415-6352
Email: MEF4@PGE.com

May 12, 2009

RE: Diablo Canyon Power Plant (DCPP)
License Renewal Feasibility Study

Ms Diane Noda, Field Supervisor,
U.S. Fish and Wildlife Service (USFWS)
2493 Portola Road, Suite B
Ventura, CA 93003

Dear Ms Noda:

Pacific Gas and Electric Company (PG&E) is conducting a License Renewal Feasibility Study to determine if it is feasible to renew the Diablo Canyon Power Plant operating licenses. If PG&E decides to pursue a renewal license application for the plant, the Federal Nuclear Regulatory Commission (NRC) will require us to consider possible impacts to all Category 2 issues (10 CFR 51.45(c); 51.53(c)(3)(iii); Regulatory Guide pg. 4.2-s-5). Category 2 issues include but are not limited to:

- Entrainment of fish and shellfish in early life stages
- Impingement of fish and shellfish
- Heat shock (thermal discharge impacts to fish and shellfish)
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Diablo Canyon Power Plant (DCPP) is located within the PG&E owner-controlled area, which consists of approximately 760 acres of land located in San Luis Obispo County, adjacent to the Pacific Ocean and roughly equidistant from San Francisco and Los Angeles. It is located directly southeast of Montana de Oro State Park and is approximately 12 miles southwest of the city of San Luis Obispo (7.5' USGS Quadrangle, Township 31 South, Range 10 East).

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- Diablo-Gates – One single-circuit 500kV line transmits power generated at the plant site a distance of 79 miles to the Gates Substation in Fresno County. This line has a 350-ft. right-of-way width.

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One additional transmission line brings power 10.25 miles into Diablo Canyon from Morro Bay power plant:

- Diablo-Mesa – One double-circuit 230kV line connecting to the existing Morro Bay-Mesa 230kV line.

There are approximately 140 miles of 500kV transmission corridor. The corridors pass through coastal mountains and foothills, interior coast valleys, and terminate in the San Joaquin Valley. Some State land (Calif. Dept. of Fish and Game) and Federal (BLM and USFS) lands occur along these routes. However, the majority (86%) of land crossed by these corridors is in private ownership.

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We would appreciate receiving comments from you on the role your agency would expect to play in a relicensing process and the scope of information you might require to fulfill those responsibilities. PG&E will include a copy of this letter and your response in any Environmental Report that may be filed subsequently with the NRC. If our decision is to pursue relicensing we would anticipate the need for further consultation with your agency

Best Regards,

(original signed)

Michael E. Fry
Senior Consulting Scientist
Environmental Services Department
San Ramon, California

Pacific Gas and Electric Company

M. Fry
Sr. Consulting Scientist
Environmental Services

Mailing Address
3401 Crow Canyon Rd.
San Ramon, Ca 94583
Tel: 925-415-6352
Email: MEF4@PGE.com

May 12, 2009

RE: Diablo Canyon Power Plant (DCPP)
License Renewal Feasibility Study

Gail Newton, Division Chief Environmental Planning:
State Lands Commission, Environmental Planning
100 Howe Ave Suite 100 South
Sacramento, CA 95825-8202

Dear Ms Newton:

Pacific Gas and Electric Company (PG&E) is conducting a License Renewal Feasibility Study to determine if it is feasible to renew the Diablo Canyon Power Plant operating licenses. If PG&E decides to pursue a renewal license application for the plant, the Federal Nuclear Regulatory Commission (NRC) will require us to consider possible impacts to all Category 2 issues (10 CFR 51.45(c); 51.53(c)(3)(iii); Regulatory Guide pg. 4.2-s-5). Category 2 issues include but are not limited to:

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We would appreciate receiving comments from you on the role your agency would expect to play in a relicensing process and the scope of information you might require to fulfill those responsibilities. PG&E will include a copy of this letter and your response in any Environmental Report that may be filed subsequently with the NRC. If our decision is to pursue relicensing we would anticipate the need for further consultation with your agency

Best Regards,

(original signed)

Michael E. Fry
Senior Consulting Scientist
Environmental Services Department
San Ramon, California

STATE OF CALIFORNIA — ARNOLD SCHWARZENEGGER, *Governor*

CALIFORNIA STATE LANDS COMMISSION
100 Howe Avenue, Suite 100-South
Sacramento, CA 95825-8202

PAUL D. THAYER, *Executive Officer*
(916) 574-1800 FAX (916) 574-1810
Relay Service From TDD Phone **1-800-735-2929**
from Voice Phone **1-800-735-2922**

Contact Phone: **(916) 574-1814**
Contact FAX: **(916) 574-1885**

June 3, 2009

File Ref: PRC 4307
PRC 4449

Michael Fry
Senior Consulting Scientist
Environmental Services
Pacific Gas and Electric Company
3401 Crow Canyon Road
San Ramon, CA 94583

Subject: Diablo Canyon Power Plant License Renewal Feasibility Study

Dear Mr. Fry:

Staff of the California State Lands Commission (CSLC) has reviewed your letter of May 12, 2009, pertaining to the above mentioned feasibility study. Under the California Environmental Quality Act (CEQA), the CSLC is a Trustee Agency and/or Responsible Agency for this project.

By way of background, the State acquired sovereign ownership of all tidelands and submerged lands and beds of navigable waterways upon its admission to the United States in 1850. The State holds these lands for the benefit of all the people of the State for statewide Public Trust purposes which include waterborne commerce, navigation, fisheries, water-related recreation, habitat preservation, and open space. The landward boundaries of the State's sovereign interests in areas that are subject to tidal action are generally based upon the ordinary high water marks of these waterways as they last naturally existed. A lease from the CSLC is required for any portion of a project extending onto State-owned lands which are under its exclusive jurisdiction.

Our records indicate that the CSLC has issued two leases to PG&E for facilities located on state-owned sovereign lands associated with Units 1 and 2 of the Diablo Canyon Power Plant. PRC 4307.9 is a 49-year Industrial Lease which began August 28, 1969, and covers the construction, operation and maintenance of a water-intake structures and breakwaters. PRC 4449.9 is a 49-year Right of Way Lease which began June 1, 1970, for the cooling water discharge channel.

As a Trustee Agency CSLC is interested in reviewing the impingement and entrainment studies and data collected, the thermal impacts of the discharge and reviewing any mitigation proposed to off-set these impacts.

Greenhouse gas (GHG) emissions information consistent with the California Global Warming Solutions Act (AB 32) and subsequent legislation should be included. This would include a determination of the greenhouse gases that will be emitted as a result of any construction and maintenance, a determination of the significance of the impact, and mitigation measures to reduce that impact.

If you have any questions regarding CSLC jurisdiction, please contact Jane Smith, Public Land Management Specialist, at (916) 574-1892 or by e-mail at smithj@slc.ca.gov. If you have any questions regarding environmental issues, please contact Steven Mindt at (916) 574-1497 or by e-mail at mindts@slc.ca.gov.

Sincerely,

Gail Newton, Chief
Division of Environmental Planning
and Management

cc: Office of Planning and Research
State Clearinghouse
P.O. Box 3044
Sacramento, CA 95812-3044

bcc: Judy Brown
Steven Mindt
Jane Smith

Pacific Gas and Electric Company

M. Fry
Sr. Consulting Scientist
Environmental Services

Mailing Address
3401 Crow Canyon Rd.
San Ramon, Ca 94583
Tel: 925-415-6352
Email: MEF4@PGE.com

May 12, 2009

RE: Diablo Canyon Power Plant (DCPP)
License Renewal Feasibility Study

Mr. Steve Edmondson, Area Office Supervisor
National Marine Fisheries Service (NMFS)
Habitat Conservation Division
777 Sonoma Ave, Room 325
Santa Rosa, CA 95404

Dear Mr. Edmondson:

Pacific Gas and Electric Company (PG&E) is conducting a License Renewal Feasibility Study to determine if it is feasible to renew the Diablo Canyon Power Plant operating licenses. If PG&E decides to pursue a renewal license application for the plant, the Federal Nuclear Regulatory Commission (NRC) will require us to consider possible impacts to all Category 2 issues (10 CFR 51.45(c); 51.53(c)(3)(iii); Regulatory Guide pg. 4.2-s-5). Category 2 issues include but are not limited to:

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Michael E. Fry
Senior Consulting Scientist
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Mailing Address
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Tel: 925-415-6352
Email: MEF4@PGE.com

May 12, 2009

RE: Diablo Canyon Power Plant (DCPP)
License Renewal Feasibility Study

Marija Vojkovich, Regional Manager:
California Department of Fish and Game (DFG)
Marine Resources Management
20 Lower Ragsdale Drive, Suite 100
Monterey, CA 93940

Dear Ms. Vojkovich:

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Senior Consulting Scientist
Environmental Services Department
San Ramon, California

Pacific Gas and *Electric Company*

M. Fry
Sr. Consulting Scientist
Environmental Services

Mailing Address
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San Ramon, Ca 94583
Tel: 925-415-6352
Email: MEF4@PGE.com

May 12, 2009

**RE: Diablo Canyon Power Plant (DCPP)
License Renewal Feasibility Study**

Dr. Jeffrey R. Single, Regional Manager
California Department of Fish and Game (DFG)
Central Region Headquarters Office
1234 E. Shaw Avenue
Fresno, CA 93710

Dear Dr. Single:

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Michael E. Fry
Senior Consulting Scientist
Environmental Services Department
San Ramon, California

Pacific Gas and *Electric Company*

M. Fry
Sr. Consulting Scientist
Environmental Services

Mailing Address
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San Ramon, Ca 94583
Tel: 925-415-6352
Email: MEF4@PGE.com

May 12, 2009

RE: Diablo Canyon Power Plant (DCPP)
License Renewal Feasibility Study

Ms Kathy Hardy, District Manager
Bureau of Land Management
Central California District,
2800 Cottage Way, Suite W-1623
Sacramento, CA 95825

Dear Ms Hardy**:**

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Best Regards,

(original signed)

Michael E. Fry
Senior Consulting Scientist
Environmental Services Department
San Ramon, California

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Central California District
2800 Cottage Way, Suite W1623
Sacramento, CA 95825
www.ca.blm.gov

In Reply Refer To:
2800 (P)
LLCAC00000

JUN 09 2009

Michael E. Fry
Senior Consulting Scientist
Environmental Services Department
Pacific Gas and Electric Company
3401 Crow Canyon Road
San Ramon, CA 94583

Dear Mr. Fry:

This letter is in response to your letter of May 12, 2009, about the Diablo Canyon Power Plant License Renewal Feasibility Study. I understand that this project includes three transmission lines which partially traverse federally-owned lands managed by the Bureau of Land Management (BLM). Consequently, the BLM is potentially a Cooperating Agency with PG&E in analyzing the proposed project.

Please work directly with the Bakersfield Field Manager as you proceed farther with your planning efforts.

Tim Smith, Bakersfield Field Manager, can be reached by mail to the Bakersfield Field Office, 3801 Pegasus Drive, Bakersfield, CA 93308; by telephone at (661) 391-6000; or by email to Tim_Smith@blm.gov.

Sincerely,

Kathy Hardy

Kathy Hardy
District Manager
Central California District

ATTACHMENT D – STATE HISTORIC PRESERVATION OFFICER CORRESPONDENCE

Pacific Gas and *Electric Company*

M. Trumbly
Cultural Resources Specialist
Environmental Services

Mailing Address
5555 Florin Perkins, Room 137
Sacramento, Ca 95826
Tel: 916-386-5436 cell: 916-201-8571
Fax:: 916-386-5425
Email: MNT7@pge.com

February 27, 2008

Milford Wayne Donaldson, State Historic Preservation Officer
Office of Historic Preservation
California Department of Parks and Recreation
1416 9th Street, Room 1442-7
Sacramento, CA 95814

RE: Diablo Canyon Power Plant (DCPP)
License Renewal Feasibility Study

Dear Mr. Donaldson:

Pacific Gas and Electric Company (PG&E) is conducting a License Renewal Feasibility Study to determine if it is feasible to renewal the Diablo Canyon Power Plant operating licenses. As part of the license renewal process, NRC requires license applicants to "assess whether any historic or archaeological properties will be affected by the proposed project." NRC may also request an informal consultation with your office at a later date under Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470), and Federal Advisory Council on Historic Preservation regulations (36 CFR 800). By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC consultation.

The current operating licenses expire in 2024 and 2025 for Units 1 and 2, respectively. If PG&E decides to pursue license renewal, based on the results of this feasibility study, the operating license would extend for an additional 20 years to 2044 and 2045. The decision to pursue license renewal has not yet been made.

Diablo Canyon Power Plant (DCPP) is located within the PG&E owner-controlled area, which consists of approximately 760 acres of land located in San Luis Obispo County, adjacent to the Pacific Ocean and roughly equidistant from San Francisco and Los Angeles. It is located directly southeast of Montana de Oro State Park and is approximately 12 miles southwest of the city of San Luis Obispo, the county seat and the nearest significant population center (Figure 2.1). The DCPP is located on the Port San Luis, Ca 7.5' USGS Quadrangle in the unsectioned area of Canada De Los Osos Y Pecho Y Islay Land Grant in Township 31 South, Range 10 East.

Three transmission lines connect the power plant to the regional grid, and are thus relevant to the License Renewal Feasibility Study (Figure 3.1-2). They include:

- Diablo-Mesa – One double-circuit line was connected to an existing Morro Bay-Mesa line 10.25 miles from DCPP with an 80-ft. right-of-way width.

- Diablo-Gates – One single-circuit line was connected to the Gates Substation in Fresno County 79 miles northeast of DCPP with a 350-ft. right-of-way width.
- Diablo Midway #2 and 3 – Two single-circuit lines were connected to the Midway Substation in Kern County 84 miles southeast of DCPP with a combined right-of-way width of 400 ft.

In total, there are approximately 170 miles of corridor that occupy approximately 4,500 acres. The corridors pass primarily through foothills sand rolling land. In addition, there are parcels of land that are agricultural and forest land.

PG&E has completed a Technical Report documenting known cultural resources within 6 miles of the DCPP and 2.4 mile corridor around the Transmission Line (Attachment A). In order to compile this information a data search was completed at the California Historical Resources Information System (CHRIS), an internal PG&E data search and using the National Register Information System on-line database. This report also describes our current Cultural Resources Management Plan for CA-SLO-2, which is located adjacent the DCPP facility.

PG&E does not expect continued DCPP operations to adversely affect cultural resources in the APE, as PG&E has no plans to alter current operations or disturb any land for the proposed project. No construction along any of the transmission lines is planned. Maintenance on the transmission lines would continue as currently performed.

If you have any questions or concerns regarding this project please feel free to call me (916) 201-8571. After your review, we would appreciate your input detailing any concerns you may have about cultural resources in the current study area or confirming PG&E's conclusion that operation of DCPP over the license renewal term would have no effect on cultural resources. This will enable us to meet our application preparation schedule. PG&E will include a copy of this letter and your response in the Environmental Report that may be submitted to the NRC as part of the DCPP license renewal application.

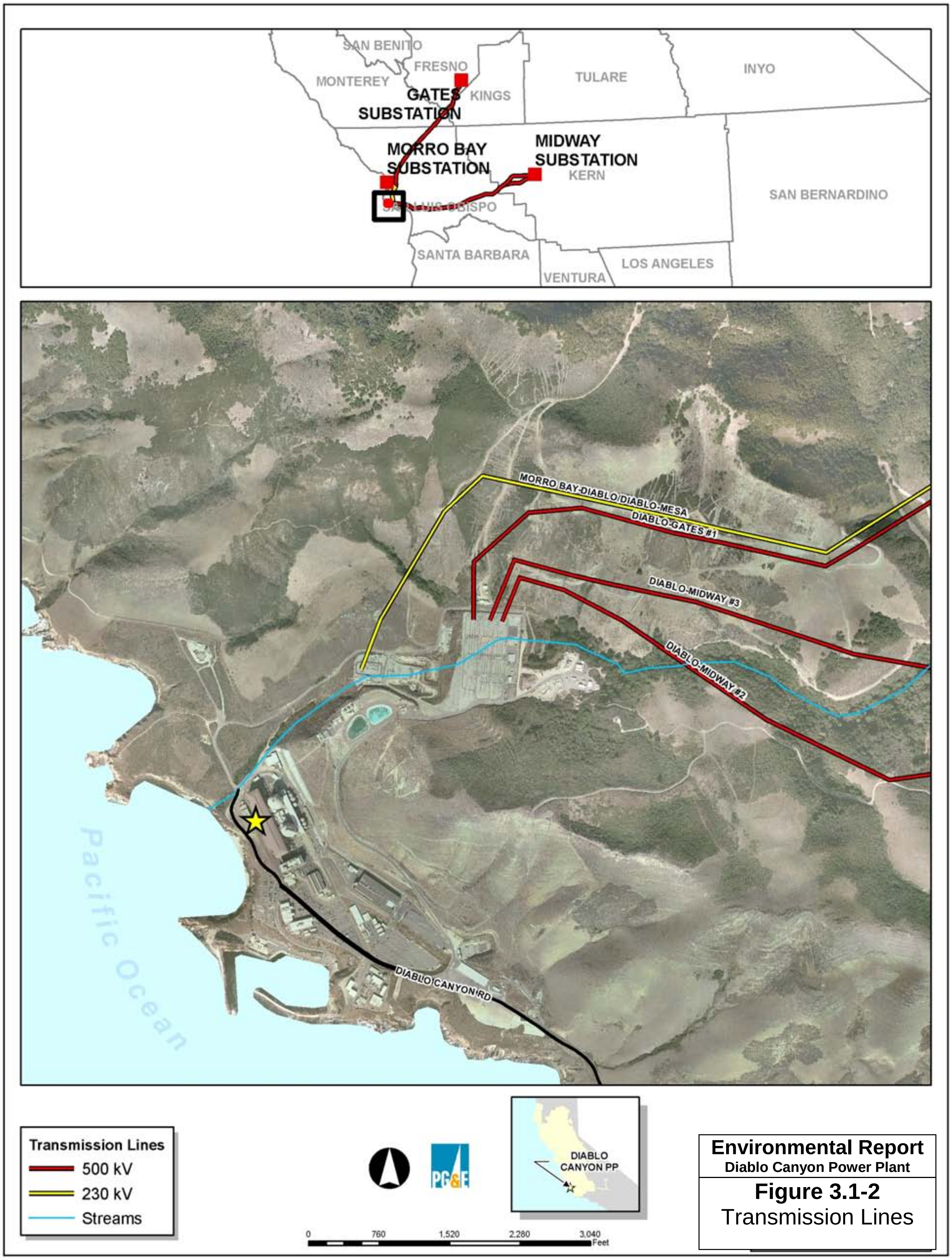
Thank you for taking the time to review this project.

Best Regards,

Maggie T

Maggie Trumbly
Cultural Resource Specialist
Enclosure (Technical Report)

Environmental Report
Diablo Canyon Power Plant
Figure 2.1-2
50-Mile Vicinity Map



Environmental Report
Diablo Canyon Power Plant

Figure 3.1-2
Transmission Lines

STATE OF CALIFORNIA – THE RESOURCES AGENCY ARNOLD SCHWARZENEGGER, *Governor*

OFFICE OF HISTORIC PRESERVATION
DEPARTMENT OF PARKS AND RECREATION
P.O. BOX 942896
SACRAMENTO, CA 94296-0001
(916) 653-6624 Fax: (916) 653-9824
calshpo@ohp.parks.ca.gov
www.ohp.parks.ca.gov

March 18, 2009

Reply in Reference To: NRC090303A

Maggie Trumbly
Cultural Resource Specialist
Pacific Gas and Electric
5555 Florin Perkins, Room 137
Sacramento, CA 95826

Re: Section 106 Consultation for License Renewal Feasibility Study for Diablo Canyon Power Plant Operating Licenses

Dear Ms. Trumbly,

Thank you for initiating consultation regarding the Federal Energy Regulatory Commission's (FERC) efforts to comply with Section 106 of the National Historic Preservation Act of 1966 (16 U.S.C. 470f), as amended, and its implementing regulation found at 36 CFR Part 800.

Pacific Gas and Electric (PG&E) is conducting a License Renewal Feasibility Study to determine if it is feasible to renew the Diablo Canyon Power Plant (DCPP) operating license. As part of the license renewal process, the NRC requires license applicants to "assess whether any historic or archaeological resources will be affected by the proposed project." Furthermore, PG&E does not expect continued operations to adversely affect cultural resources in the APE, nor does it expect to alter current operations, either through planned construction or ground disturbance. Maintenance on the transmission lines is expected to continue as currently performed. The decision to pursue license renewal has not been made.

You have requested that I comment on concerns or questions I may have regarding cultural resources located within the study area and that I assess your conclusion that operation of the DCPP over the license renewal term will not affect cultural resources.

To support these findings, you have submitted maps, a technical report, historical documentation and cultural resource records for a study area consisting of three transmission lines encompassing approximately 170 miles of corridor occupying approximately 4500 acres. Based on the information provided, I have the following comment:

1) Relicensing will require the development of a Programmatic Agreement and a Historic Properties Management Plan in consultation with this office.

18 March 2009
Page 2 of 2

NRC090303A

Thank you for seeking my comments and considering historic properties as part of your project planning. If you have any questions or concerns, please contact Ed Carroll of my staff at (916) 653-9010 or at email at ecarroll@ca.parks.gov.

Sincerely,

Susan K Stratton for

Milford Wayne Donaldson, FAIA
State Historic Preservation Officer

-- Draft --

PROGRAMMATIC AGREEMENT
BETWEEN
THE NUCLEAR REGULATORY COMMISSION,
{PACIFIC GAS AND ELECTRIC COMPANY,}
THE CALIFORNIA STATE HISTORIC PRESERVATION OFFICER,
{AND THE ADVISORY COUNCIL ON HISTORIC PROPERTIES}
REGARDING THE
MANAGEMENT OF HISTORIC PROPERTIES
THAT MAY BE AFFECTED BY THE
THE LICENSE ISSUANCE FOR THE
DIABLO CANYON POWER PLANT,
SAN LUIS OBISPO COUNTY, CALIFORNIA

WHEREAS, the Nuclear Regulatory Commission (NRC) proposes to issue a new license granting Pacific Gas and Electric Company (PG&E) the right to operate and maintain the Diablo Canyon Power Plant (DCPP), in accordance with the Federal Energy Reorganization Act of 1974, as amended, Pub. L. 93-438, 88 Stat. 1233 (42 U.S.C. 5801 et seq.); and

WHEREAS, the NRC has determined that the issuance of the license may have adverse effects on, properties determined to be eligible for inclusion in the National Register of Historic Places (NRHP), pursuant to 36 CFR 800 of the regulations implementing Section 106 of the National Historic Preservation Act (16 U.S.C § 470f); and

WHEREAS, the NRC has determined that the issuance of a new operating license is an "Undertaking" as defined at 36 CFR 800.16(y), and has consulted the State Historic Preservation Officer (SHPO) pursuant to 36 CFR Part 800, regulations effective August 5, 2004, implementing Section 106 of the National Historic Preservation Act, as amended (16 U.S.C.§ 470f) and invited the Advisory Council on Historic Preservation (ACHP) under 36 CFR §800.6(a)(1)(i)(C) to participate to address potential effects of the Undertaking on historic properties and the ACHP has chosen {not} to participate; and

WHEREAS, the NRC, in consultation with the State Historic Preservation Officer, has thoroughly considered alternatives, has determined that potential adverse effects to historic properties cannot be fully determined prior to approval of the undertaking, that implementation of the Historic Properties Management Plan (HPMP) prescribed in Stipulation II of the Programmatic Agreement (PA) will satisfactorily take into account the Undertaking's potential adverse effects to these historic properties; and

WHEREAS, Appendix A of this Programmatic Agreement provide a description of the of the DCPP Area of Potential Effect as agreed upon in consultation with the NRC, PG&E, SHPO, {ACHP}, and Tribes; and

WHEREAS, the NRC has consulted with the {insert tribal groups} and has invited the Tribes to sign this PA as concurring parties; and

WHEREAS, PG&E, as the licensee, has participated in consultation per 36 CFR §800.2(c)(4), and will have significant responsibility for carrying out the terms of this PA and has been invited to participate as a signatory {or concurring party} to this PA; and

WHEREAS, the NRC will require PG&E to implement the provisions of this Programmatic Agreement as a condition of issuing the new license for DCPP; and

NOW THEREFORE, the NRC, PG&E, {ACHP}, and the SHPO agree that the Undertaking shall be implemented in accordance with the following Stipulations in order to take into account the effects of the Undertaking on the historic properties and further agree that these Stipulations shall govern the Undertaking and all of its parts until this PA expires or is terminated.

STIPULATIONS

I. DEFINITIONS

The definitions found at 36 CFR § 800.16 and California Public Resources Code 2100 et seq apply throughout this PA. Those definitions are supplemented below.

Area of Potential Effect. The Undertaking's Area of Potential Effect (APE) covers all areas that could be affected by the undertaking and was defined in consultation with the SHPO, see Attachment {A}; and

"*Concurring Parties*" means invited parties, including tribes and members of the public, who concur by signing this PA. Concurring parties may propose amendments to this PA.

Signatories. The NRC, {PG&E, ACHP}, and the SHPO. Signatories may propose amendments to this PA and have the exclusive authority to terminate the PA.

II. TREATMENT OF HISTORIC PROPERTIES

The NRC shall ensure that the following measures are carried out:

PG&E shall ensure that the potential adverse effects of the Undertaking are resolved by developing, finalizing, and implementing a management plan known as *Historic **Properties Management Plan for the Diablo Canyon Power Plant, San Luis Obispo County, California***.

1. The final Historic Properties Management Plan (HPMP) shall detail the historic preservation program to:
   - (a) inventory, evaluate, manage, and treat adverse effects to historic properties within the defined APE;
   - (b) consult and coordinate with government agencies, tribes, and the public with regard to implementation of the HPMP;
   - (c) provide for curation of archaeological and historical items associated with the historic preservation program for the Undertaking;
   - (d) support interpretation of historic properties to the public and other public involvement in historic preservation; and
   - (e) define the roles and responsibilities of the NRC and PG&E in any long-term management of historic properties in the APE.

-- *Draft* --

2. Within one (1) year of the date of execution of this PA, an Administrative Draft HPMP shall be prepared and submitted by PG&E to the NRC, {ACHP}, SHPO, tribes, and other parties who have participated in the development of this PA for review and comment. The NRC shall provide written comments to PG&E. The NRC will direct PG&E to make revisions to the Administrative Draft HPMP consistent with the written comments.

3. Should any party to this PA object to the content of the Draft or Final HPMP, the NRC will proceed to resolve the objection consistent with Stipulation VIII, below.

4. Final HPMP shall be implemented as follows.

   Upon written acceptance by the NRC, {ACHP}, and the SHPO, the HPMP shall be implemented by PG&E under the authority of this PA for compliance with NHPA §106 for the Undertaking.

   Implementation of the HPMP shall be monitored by the NRC, the SHPO, {ACHP}, tribes, and other parties to this PA through review of an annual ***Historic Preservation Compliance Report***. Such report shall include any scheduling changes proposed, any problems encountered, sites monitored and their conditions, and any disputes and objections received in PG&E's efforts to implement the HPMP.

5. Changes to the HPMP after its implementation shall be made as follows:

   Should PG&E, the NRC, {the ACHP}, or SHPO determine that changes to the HPMP are warranted to modify existing elements, or to add or delete some elements of the historic preservation program defined by the HPMP, PG&E and the NRC shall consult to make the agreed upon changes. The NRC shall then give notice to the SHPO {and the ACHP}, and consult in writing with the SHPO {and the ACHP} to determine if proposed changes constitute a significant revision of the historic preservation program. The SHPO {and the ACHP} shall have 30 days to respond in writing to the NRC's proposed changes to the HPMP. If the NRC, {the ACHP,} and SHPO concur that the proposed changes do not constitute a significant revision to the HPMP, then the NRC and PG&E shall proceed to revise and implement the appropriate elements of the HPMP. Failure by the SHPO {or the ACHP} to respond in writing within 30 days shall be taken as concurrence by the SHPO or the ACHP regarding the proposed change in the HPMP. If the NRC, {the ACHP,} or the SHPO believes the proposed changes to the HPMP constitute a significant revision to the historic preservation program, the signatories shall proceed to consult according to Stipulation VIII of this PA. Should the NRC,{the ACHP,} or the SHPO object regarding proposed changes to the HPMP, the parties shall proceed according to Stipulation VIII of this PA.

6. PG&E shall describe any revision to the HPMP, whether determined significant or insignificant, in its annual Historic Preservation Compliance Report.

7. Until the finalized HPMP is executed and implemented, the NRC will comply with regulations at 36 CFR §800.4–800.6. PG&E shall assist and cooperate with the NRC during this interim period.

III. NATIVE AMERICAN CONSULTATION

The NRC has consulted with the {insert Tribal Groups} regarding the proposed Undertaking and its potential effect on the aforementioned cultural properties, and will continue to consult with the Tribes, and will afford the Tribes, should they so desire, the opportunity to participate in the implementation of the PA as concurring parties. Such participation may include, but is not necessarily limited to, monitoring during archaeological fieldwork prescribed in Stipulation II. Should the Tribes agree to participate as herein set forth, the NRC & PG&E will make an effort to reach a mutually acceptable agreement with the Tribes regarding the manner in which they will participate in the implementation of this PA, and regarding any time frames or other matters that may govern the nature, scope, and frequency of such participation.

IV.TREATMENT OF HUMAN REMAINS OF NATIVE AMERICAN ORIGIN

The parties to this PA agree that Native American burials and related items discovered during implementation of the terms of the PA will be treated in accordance with the requirements of the 5097 of the California Public Resource Code.

V. DISCOVERIES AND UNANTICIPATED EFFECTS

If it is determined that during implementation of the HPMP, that there will be an affect to a previously unidentified property that may be eligible for the National Register or a known historic property in an unanticipated manner, the NRC and PG&E will address the discovery or unanticipated effect in accordance with those provisions of the HPMP that relate to the treatment of discoveries and unanticipated effects. The NRC at its discretion may hereunder assume any discovered property to be eligible for inclusion in the National Register. NRC compliance with this stipulation shall satisfy the requirements of 36 CFR § 800.13(a)(2).

VI. STANDARDS

1. <u>Professional Qualifications</u>. All activities prescribed by Stipulations II., III., IV., and V. of this PA shall be carried out under the authority of the NRC by or under the direct supervision of a person or persons meeting at a minimum the Secretary of Interior's Standards Professional Qualifications Standards (48 FR 44738-39) (PQS) in the appropriate disciplines.

2. <u>Historic Preservation Standards:</u> All activities prescribed by Stipulations II., III., IV., and V. of this PA shall reasonably conform to applicable standards and guidelines established by the *Secretary of Interior's Standards and Guidelines for Archaeology and Historic Preservation* (48 FR 44716-44740) and SHPO.

3. <u>Curation:</u> The NRC and PG&E shall ensure that, to the extent permitted by applicable federal law, the materials and records resulting from the activities prescribed by Stipulations II., III., IV., and V. of this PA are curated in accordance with 36 CFR Part 79.

VII. EMERGENCY SITUATIONS

1. Should the NRC find it necessary to implement undertakings within 30 days of declared emergencies (as defined at 36 CFR 78.2), or undeclared emergencies where there are imminent threats of major natural disaster (including human caused wildfire) or national security such that emergency actions are necessary for the preservation of human life or property, the NRC Supervisor shall within seven (7) working days of the date the

emergency declaration notify the SHPO and the Council of the emergencies, and advise them that the NRC will follow either

(a) provisions of this PA, and where time permits, the SHPO and {ACHP} agree to provide comments within seven (7) working days or less as situations warrant; or
(b) provisions of 36 CFR 800.

2. PG&E may respond to damage to or destruction of Facilities within the APE that are the result of a natural disaster (including human caused wildfire), or are otherwise of an unexpected, serious nature requiring immediate repair and restoration of the Facilities, including but not limited to the collapse of or serious damage to a transmission line tower, or repair of a fallen conductor. PG&E may respond to such situations without prior notification to or authorization from the NRC provided that PG&E reports to the appropriate NRC district Lands Officer such emergency repairs by 8 AM the first business day following initiation of the emergency repair. PG&E and the NRC will comply with the “Emergency Situations” provisions of the HPMP or the NRC will otherwise comply with provisions of this PA or with provisions of 36 CFR 800.

VIII. RESOLVING OBJECTIONS

1 Should the SHPO, the ACHP, or the NRC object at any time, to the manner in which the terms of this PA are implemented, the NRC will immediately notify the SHPO and the ACHP, and request SHPO and the Council comments on the objection within 30 days, and then proceed to consult with the SHPO and the ACHP for no more than 30 days to resolve the objection. The NRC will take any comments provided by the SHPO into account.

If the NRC determines that the objection can be resolved within the consultation period, the NRC may authorize the disputed action to proceed in accordance with the terms of such resolution.

2 If at the end of the 30 day consultation period, the NRC determines that the objection cannot be resolved through such consultation, the NRC will forward all documentation relevant to the objection to the Council per 36 CFR §800.2(b)(2). Any comments provided by ACHP within 30 days after its receipt of all relevant documentation will be taken into account by the NRC in reaching a final decision regarding the objection. The NRC will notify the SHPO, the ACHP, and PG&E in writing of its final decision within 14 days after it is rendered. The NRC shall have the authority to make the final decision resolving the objection.

3 The NRC’s responsibility to carry out all other actions under this PA that are not the subject of the objection will remain unchanged. The NRC may implement that portion of the Undertaking subject to objection under this stipulation after complying with subsection 3.2 of this stipulation.

4 At any time during implementation of the terms of this PA, should an objection pertaining to the PA or HPMP be raised by a member of the public, the NRC shall immediately notify the SHPO about the objection and take the objection into account. The SHPO and the Council may comment on the objection to the NRC. The NRC shall consult with the objecting party for no more than 30 days. Within 14 days following closure of consultation, the NRC will render a decision regarding the objection and notify

all parties of its decision in writing. In reaching its final decision, the NRC will take into account all comments from the parties regarding the objection. The NRC shall have the authority to make the final decision resolving the objection. Any dispute pertaining to the NRHP eligibility of historic properties or cultural resources covered by this PA will be addressed by the NRC per 36 CFR §800.4(c)(2). The NRC shall determine if Stipulation 3.1 and 3.2 shall be implemented.

IX. AMENDMENT

1. Any party to this PA may at any time propose amendments, whereupon all parties shall consult to consider such amendments pursuant to 36 CFR §800.6(c)(7) and §800.6(c)(8). This PA may be amended only upon written agreement of the signatories.

2. Each attachment to the PA may be individually amended through consultation of the parties without requiring amendment of the PA, unless the signatories through such consultation decide otherwise.
3. Amendments to this PA shall take effect on the dates that they are fully executed by the signatories.

X. TERMINATION

1. If this PA is not amended as provided for in Stipulation IX, or if either signatory party proposes termination of this PA for other reasons, the signatory party proposing termination shall, in writing, notify the other parties to this PA, explain the reasons for proposing termination, and consult with the other parties for at least 30 days to seek alternatives to termination. Such consultation shall not be required if USFS proposes termination because the Undertaking no longer meets the definition set forth in 36 CFR § 800.16(y).

2. Should such consultation result in an agreement on an alternative to termination, then the parties shall proceed in accordance with the terms of that agreement.

3. Should such consultation fail, the signatory party proposing termination may terminate this PA by promptly notifying the other parties to this PA in writing. Termination hereunder shall render this PA without further force or effect.

4. If this PA is terminated hereunder, and if the NRC determines that the Undertaking will nonetheless proceed, then the NRC shall either consult in accordance with 36 CFR § 800.6 to develop a new PA or request the comments of the ACHP pursuant to 36 CFR Part 800.

XI. CONFIDENTIALITY OF RECORDS AND INFORMATION

The signatories shall maintain the confidentiality of records and information pertaining to the location and nature of cultural resources, including historic properties about which there are culturally sensitive issues, consistent with NHPA §304 and ARPA Section 9. The NRC may determine that certain records and files are appropriate to distribute to parties outside the agency, including tribes who have participated in this PA.

-- Draft --

XII. DURATION OF THIS PA

The signatories shall consult to reconsider the terms of this PA within ten (10) years of the date this PA is executed, and subsequently within ten (10) years after each date of execution of a renewal of this PA for the life of the operating license. Reconsideration may include continuation of the PA as originally executed or amended, or termination.

XII. EFFECTIVE DATE

This PA shall take effect on the date that it has been fully executed by the signatories. Attachments to this PA shall take effect on the dates they are fully executed by the signatories, or such other self-executing dates as may be described in those attachments.

Execution and implementation of this is evidence that the NRC has afforded the ACHP a reasonable opportunity to comment on the Undertaking and its effects on historic properties. The signatories to this PA represent that they have the authority to sign for and bind the entities on behalf of whom they sign.

-- ***Draft*** --

SIGNATORIES

ADVISORY COUNCIL ON HISTORIC PRESERVATION

By, ______________________________ Date: _______________
John Fowler, Executive Director

STATE OF CALIFORNIA, OFFICE OF HISTORIC PRESERVATION

By, ______________________________ Date: _____________
Milford Wayne Donaldson, State Historic Preservation Officer

Nuclear Regulatory Commission

By, ______________________________ Date: _____________

-- Draft --

CONCURRING PARTIES

Pacific Gas and Electric Company

By, _________________________________ Date: _______________

ATTACHMENT E – COASTAL ZONE CONSISTENCY CERTIFICATION

This is the Diablo Canyon Power Plant (DCPP) certification to the U.S. Nuclear Regulatory Commission (NRC) that the renewal of the DCPP Units 1 and 2 Operating Licenses will be consistent with enforceable policies of the federally approved state coastal zone management program. The certification describes the proposed action (i.e. license renewal), DCPP background, anticipated environmental impacts, California Coastal Management Program (CCMP) policies, and DCPP compliance status.

This Certification has not yet been submitted to the California Coastal Commission for review.

Pacific Gas and Electric Company

James R. Becker
Site Vice President

Mailing Address
Diablo Canyon Power Plant
Mail Code 104/6/601
P.O. Box 3
Avila Beach, CA 93424

805-545-3462
Fax: 805-545-6445

November 23, 2009

Peter M. Douglas, Executive Director
California Coastal Commission
45 Fremont Street, Suite 2000
San Francisco, CA 94105-2219

RE: Federal Consistency Certification for Federal Permit and License Applicants
Diablo Canyon Power Plant
License Renewal Application

Dear Mr. Douglas:

Pacific Gas and Electric Company (PG&E) is requesting concurrence with the enclosed Federal Consistency Certification for Federal Permit and License Applicants. The certification presents PG&E's position that continued operation of the Diablo Canyon Power Plant (DCPP) in San Luis Obispo County, CA complies with California's Coastal Zone Management Program and will be conducted in a manner consistent with such Program.

As part of the application process to the U.S. Nuclear Regulatory Commission (NRC) requesting renewal of the DCPP Operating Licenses, PG&E performed a review for consistency with the California Coastal Management Program. In conjunction with the application submittal, PG&E must certify to the NRC and the State of California that DCPP operations and activities are in compliance with the Coastal Zone Management Act.

The certification includes a set of findings relating the coastal effects of continued operations of DCPP to the relevant policies and enforceable rules of the California Coastal Management Program. Attachment 1 to the certification reproduces each Program policy and rule and explains the basis for PG&E's conclusion that renewal of the DCPP Operating Licenses will either comply with and will be conducted in a manner consistent with that Program policy or rule or why that particular policy or rule is not applicable to license renewal.

Per NRC regulations for license renewal (10 CFR 54), PG&E has prepared an Environmental Report as Appendix E of the license renewal application (enclosed). The Environmental Report includes a description of the proposed action and the affected environment, and an analysis of environmental consequences of the proposed action and mitigating actions. Also included in the Environmental Report is a complete list of license, permits, and other approvals from Federal, State, and local authorities for current DCPP operations, and approvals and consultations that are required for the period of extended operations. A summary of this information is provided in the enclosed consistency certification.

After your office reviews the Consistency Certification, PG&E requests a letter concurring with the enclosed Federal Consistency Certification for Federal Permit and License Applicants.

Please call Mark Krausse at 916-386-5709 if you have any questions or require any additional information to review the attached certification.

Sincerely,

(Original Signed)

James R. Becker
Site Vice President
Diablo Canyon Power Plant
Pacific Gas and Electric Company

Enclosures: Federal Consistency Certification for Federal Permit and License Applicants

Diablo Canyon Power Plant License Renewal Application to the NRC

Federal Consistency Certification for Federal Permit and License Applicants

I. AUTHORITY

Pacific Gas & Electric (PG&E) is submitting this Coastal Consistency Certification in compliance with 15 CFR Section 930.57 *et seq.* of the National Oceanic and Atmospheric Administration (NOAA) Federal Consistency Regulations (15 CFR 930).

II. CERTIFICATION

As required by 15 CFR §930.57(b), PG&E Diablo Canyon Power Plant has concluded that the proposed Management Plan complies with the enforceable policies of California's approved management program, and will be conducted in a manner consistent with such program. The DCPP License Renewal Environmental Report included with the management plan provides the basis for the finding and is incorporated by reference.

III. PROJECT DESCRIPTION

Proposed Action

The NRC operating licenses for DCPP Units 1 and 2 authorizes reactor operation until 2024 and 2025, respectively. NRC regulations in 10 CFR Parts 51 and 54 provide for the renewal of existing plant operating licenses and, in fact, as of January 2009 the NRC has renewed 51 operating licenses. In December 2009, PG&E submitted the license renewal application for DCPP to the NRC seeking to extend the license terms to 2044 and 2045. Attachment E-2 is the PG&E application for license renewal to the NRC. As part of the license renewal application, PG&E included not only an assessment of systems, structures, and components important to continued safe plant operation, but also an extensive assessment of the environmental impacts of continued plant operation.

Background Information

DCPP is a nuclear-powered steam electric generating facility located within the California coastal zone, in San Luis Obispo County, just south of Montana De Oro State Park, and twelve miles southwest of the city of San Luis Obispo. From 1980 through 2010, San Luis Obispo's County's population is projected to grow from 155,345 to 269,734 (growth of 57.6 percent). Approximately 45 percent of the area within a 50-mile radius of DCPP encompasses waters of the Pacific Ocean. Figures E-1 and E-2 are DCPP 50- and 6-mile vicinity maps, respectively.

The permanent (non-outage) DCPP workforce consists of approximately 1,350 employees. More than 95 percent reside in San Luis Obispo and Santa Barbara Counties. The DCPP reactors are currently on nominal 18-month refueling cycles. During refueling outages, site employment increases above the permanent workforce by as many as 1,200 for approximately 40 days of temporary duty. PG&E has no plans to add employees as a result of license renewal.

Each DCPP unit is a pressurized water nuclear reactor with an expected total output of approximately 3,411 MW thermal. DCPP uses a once-through cooling heat sink system that withdraws water from and discharges to the Pacific Ocean. The intake structure has four circulating water pumps (two per unit). The four pumps provide a continuous supply (nominally 867,000 gpm for each unit) of condenser cooling water. After moving through the condensers, water is discharged back into the Pacific Ocean through a shoreline outfall located at Diablo Cove.

PG&E has not identified any refurbishment activities necessary to allow operation for an additional 20 years, and has identified no significant environmental impacts from programs and activities for managing the effects of aging. As such, renewal would result in a continuation of environmental impacts currently regulated, and already permitted by the state. Table E-1 lists State and Federal licenses, permits, and other environmental authorizations for current DCPP operations, and Table E-2 identifies compliance activities associated specifically with NRC license renewal.

Three transmission lines were constructed to supply offsite power to DCPP and to connect DCPP to the electric grid (Figure E-3). The transmission system is operated and maintained by PG&E. One double-circuit line was connected to an existing Morro Bay-Mesa line 10.25 miles from DCPP with an 80-ft right-of-way width. One single-circuit line was connected to the Gates Substation in Fresno County 79 miles from DCPP with a 350-ft right-of-way width. Lastly, two single-circuit lines were connected to the Midway Substation in Kern County 84 miles from DCPP with a combined right-of-way width of 400 ft. In total, for the specific purpose of connecting DCPP to the transmission system, PG&E has approximately 170 miles of corridor that occupy approximately 4,500 acres. The corridors pass primarily through foothills and rolling land. In addition, there are parcels of land that are agricultural or forested. The areas are mostly remote. The proposed action, renewing the DCPP operating license for an additional 20 years, would not require additional transmission lines, nor is PG&E anticipating that this action would change any corridor maintenance practices. Coastal regulations require protection of vegetation in wetlands, along intermittent stream corridors, and on steep slopes, and protection of threatened and endangered species. Vegetation management contractors of PG&E are required to adhere to vegetation management specifications within PG&E transmission corridors.

Environmental Impacts of DCPP License Renewal

The NRC has prepared a Generic Environmental Impact Statement (GEIS) assessing impacts that nuclear power plant license renewal could have on the environment, and has codified its findings in 10 CFR 51, Subpart A, Appendix B, Table B-1 (NRC 1996). The codification identified 92 potential environmental issues, 69 of which the NRC identified as having SMALL impacts and termed “Category 1 issues.” The NRC defines “SMALL” as:

> SMALL – For the issue, environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purpose of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small as the term is used in this table. (10 CFR 51, Subpart A, Appendix B, Table B-1)

The NRC based its assessment of license renewal impacts on its evaluations of impacts from current plant operations. The NRC codification and the GEIS discuss the following types of Category 1 environmental issues:

- Surface water quality, hydrology, and use
- Aquatic ecology
- Groundwater use and quality
- Terrestrial resources
- Air quality
- Land use
- Human health
- Postulated accidents
- Socioeconomics
- Uranium fuel cycle and waste management
- Decommissioning

In its decision-making for plant-specific license renewal applications, absent new and significant information to the contrary, NRC relies on its codified findings, as amplified by supporting information in the GEIS, for assessment of environmental impacts from Category 1 issues [10 CFR 51.95(c)(4)]. For plants such as DCPP that are located in coastal areas, many of these issues involve impacts to the coastal zone. Table E-3 lists the 92 issues, identifies them as Category 1 or 2, and describes their relevance or environmental impact at DCPP as discussed in the Environmental Report. Of the 69 Category 1 issues identified in the GEIS, 52 are applicable to DCPP[1].

The NRC has identified 21 issues as "Category 2," for which license renewal applicants must submit additional site-specific information[2]. Of these, 7 apply to DCPP[3], and could involve impacts to the coastal zone.

[1] The remaining Category 1 issues do not apply to DCPP because they are associated either with design or operational features the DCPP does not have (e.g., cooling ponds), or to an activity (i.e., refurbishment) that DCPP will not undertake for purposes of license renewal.

[2] 10 CFR 51, Subpart A, Appendix B, Table B-1 also identifies 2 issues as “NA” for which the NRC could not come to a conclusion regarding categorization. PG&E believes that these issues, chronic effects of electromagnetic fields and environmental justice, do not affect “coastal zone” as that phrase is defined by the Coastal Zone Management Act [16 USC 1453(1)].

PG&E evaluated the environmental issues set forth in the GEIS in the *Diablo Canyon Power Plant Applicant's Environmental Report - Operating License Renewal Stage,* submitted as part of the DCPP license renewal application to NRC (Appendix E of Attachment E-2).

IV. CONSISTENCY WITH PROVISIONS OF THE CALIFORNIA COASTAL ACT

Attachment E-1 addresses the consistency of the Proposed Action with each article of the California Coastal Act (Division 20, Chapter 3, California Public Resource Code). These articles include General, Public Access, Recreation, Marine Environment, Land Resources, Development, and Industrial Development.

V. STATE NOTIFICATION

By this certification that the Diablo Canyon Power Plant License Renewal Feasibility Study is consistent with the California Coastal Management Program, the State of California is notified that it has six months from receipt of this letter and accompanying information in which to concur with or object to PG&E certification. However, pursuant to 15 CFR 930.63(b), if California has not issued a decision within three months following commencement of State agency review, it shall notify PG&E and the Federal agency of the status of the matter and the basis for further delay. The State's concurrence, objection, or notification of review status shall be sent to:

Brian Holian Director of Division of License Renewal U.S. Nuclear Regulatory Commission One White Flint North 11555 Rockville Pike Rockville, MD 20852-2738	James Becker Site Vice President Pacific Gas and Electric Company Diablo Canyon Power Plant P.O. Box 3, Mail Code 104/6/601 Avila Beach, CA 93424

VI. REFERENCES

1. Guide to the Central California Marine Protected Areas: Pigeon Point to Point Conception. California Department of Fish and Game. 2007. Available at http://www.dfg.ca.gov/mlpa/pdfs/ccmpas_guide.pdf. Accessed 6/30/2009.

2. Division 20, Chapter 3, Coastal Resources Planning and Management Polices. California Public Resources Code. Available at http://www.coastal.ca.gov/fedcd/cach3.pdf. Accessed 6/30/2009.

3. Diablo Canyon Power Plant NPDES Permit, CA 0003751; Order No. 90-09, Central Coast Regional Water Quality Control Board, May 1990.

[3] The remaining Category 2 issues do not apply to DCPP because they are associated either with design or operational features the DCPP does not have (e.g., cooling ponds), or to an activity (i.e., refurbishment) that DCPP will not undertake for purposes of license renewal.

4. NUREG-1437: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS), Volumes 1 and 2. U.S. Nuclear Regulatory Commission. Washington, DC. 1996.

5. Office of Nuclear Reactor Regulations, LIC-203, Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues, Revision 1. U.S. Nuclear Regulatory Commission. 2004.

TABLE E-1
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT DCPP OPERATIONS

Agency	Authority	Requirement	Number	Issue or Expiration Date[4]	Activity Covered
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.), 10 CFR 50.10	License to Operate	DPR– 80 – Unit 1 DPR– 82 – Unit 2	Issued 11/02/1984 Expires 11/02/2024 Issued 11/26/1985 Expires 08/26/2025	Operation of Units 1 and 2
Central Coast Regional Water Quality Control Board	Clean Water Act (33 USC 1251 et seq.)	California Pollutant Discharge Elimination System (NPDES) Permit	CA0003751	Issued 05/11/1990 Expired 07/01/1995	Plant discharges to the Pacific Ocean
State Lands Commission	Public Resources Code 4307.9	Lease	2231-10-0044	Issued 08/28/1969 Expires 08/28/2018	Lease for Breakwaters
State Lands Commission	Public Resources Code 4449.9	Right-of-Way	2231-10-0048	Issued 06/01/1970 Expires 06/01/2019	Right-of-Way for Breakwaters
Department of Interior	Bureau of Land Management	Right-of-Way	2231-10-0041	Issued 08/22/1969 Expires 08/22/2018	Right-of-Way for Construction and Maintenance of Breakwaters
California Department of Toxic Substances Control (DTSC)	Ca H&S Code Section 25200, CCR Title 22 Division 4.5.	RCRA Equivalent Waste Treatment Storage & Disposal (TSDF) Permit	CAD077966349	Issued 11/16/2006 Expires 07/30/2016	Operation of Hazardous Waste Facility at DCPP
San Luis Obispo County Environmental Health Department	N/A	Underground Storage Tank Operating Permit & Hazardous Materials Handler Authorization	40-000-17604-006 40-000-17604-002	Issued 01/01/2009 Expired 12/31/2009	Operation of Diesel Storage Tanks

[4] Issuance and expiration dates are accurate as of 08/30/2009.

TABLE E-1
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT DCPP OPERATIONS

Agency	Authority	Requirement	Number	Issue or Expiration Date[4]	Activity Covered
National Marine Fisheries Service	Endangered Species Act of 1973 (16 USC 1531-1544)	Biological Opinion and Incidental Take Statement		Issued 09/18/2008 Expires 08/26/2025	Possession and disposition of impinged or stranded sea turtles
San Luis Obispo County Air Pollution Control District Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	919-3	Issued 07/21/2009 Expires 06/30/2010	Operation of the Emergency Diesel Generators (DCPP)	
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	886-1	Issued 04/30/2009 Expires 03/31/2010	Operation of the Emergency Diesel Generator (EOF)
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	49-1	Issued 07/21/2009 Expires 06/30/2010	Operation of the Auxiliary Boiler
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	533-2	Issued 07/21/2009 Expires 06/30/2010	Operation of the Abrasive Blast Facility
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	338-1	Issued 07/21/2009 Expires 06/30/2010	Operation of a Paint Spray Booth
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	415-1	Issued 08/22/2007 Expires 06/30/2010	Operation of Portable Sandblast Devices
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	546-1	Issued 08/05/2009 Expires 07/31/2010	Operation of a non-retail gasoline dispensing facility

TABLE E-1
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT DCPP OPERATIONS

Agency	Authority	Requirement	Number	Issue or Expiration Date[4]	Activity Covered
San Luis Obispo County Air Pollution Control District	Clean Air Act (42 USC 7401, et seq.)	Permit to Operate	1065-5	Issued 07/21/2009 Expires 06/30/2010	Operation of a transportable diesel-fueled internal combustion unit
San Luis Obispo County Public Health Department	Safe Drinking Water Act (42 USC 300 F, et seq.)	Non-Community Drinking Water System Permit	PT 0004769	N/A	Authorization to operate non-community drinking and domestic water system
Port San Luis Harbor District	N/A	Lease Agreement	2232-11-0041 2232-11-0037 2232-11-0038	Issued 07/01/1986 Expires 06/30/2011	For access road enlargement and siren location
California Secretary of Resources	California Department of Fish and Game	License	710027-01	Issued 04/23/2009 Expires 12/31/2009	Surface Canopy Kelp Harvesting
California Secretary of Resources	California Department of Fish and Game	Special Use Permit	710006-02	Issued 12/31/1999 Does not expire	Removal of Benthic Kelp from the DCPP Intake Cove Exclusion Zone

TABLE E-2
ENVIRONMENTAL AUTHORIZATIONS FOR DCPP LICENSE RENEWAL

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License Renewal	Environmental Report submitted in support of license renewal application.
U.S. Fish and Wildlife Service (USFWS)	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires federal agency issuing a license to consult with USFWS (Attachment C of Environmental Report).
California Central Coast Regional Water Quality Control Board	Clean Water Act Section 401 (33 USC 13411)	Certification	State issuance of NPDES permit (Section 9.1.5) constitutes 401 certification (Attachment B of Environmental Report)
California Coastal Commission	Federal Coastal Zone Management Act (16 USC 1452 et seq.)	Certification	Requires applicant to prove certification to Federal agency issuing the license renewal would be consistent with the Federally approved State Coastal Zone Management program. Based on its review of the proposed activity, the State must concur with or object to the applicant's certification (Attachment E of Environmental Report).
California State Office of Historic Preservation	National Historic Preservation Act Section 106 (16 USC 470f)	Consultation	Requires federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Officer (SHPO). SHPO must concur that license renewal will not affect any sites listed or eligible for listing (Attachment D of Environmental Report).

TABLE E-3
DCPP LICENSE RENEWAL NEPA ISSUES

Issue[a]	GEIS Category	Section of the Environmental Report	Relevance at DCPP/Environmental Impact
Surface Water Quality, Hydrology, and Use (for all plants)			
1. Impacts of refurbishment on surface water quality	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
2. Impacts of refurbishment on surface water use	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
3. Altered current patterns at intake and discharge structures	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
4. Altered salinity gradients	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
5. Altered thermal stratification of lakes	1	N/A	Issue applies to a plant feature, discharge to a lake, which DCPP does not have.
6. Temperature effects on sediment transport capacity	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
7. Scouring caused by discharged cooling water	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
8. Eutrophication	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
9. Discharge of chlorine or other biocides	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
10. Discharge of sanitary wastes and minor chemical spills	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
11. Discharge of other metals in waste water	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
12. Water use conflicts (plants with once-through cooling systems)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.

TABLE E-3
DCPP LICENSE RENEWAL NEPA ISSUES

Issue[a]	GEIS Category	Section of the Environmental Report	Relevance at DCPP/Environmental Impact
13. Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	NA, and discussed in Section 4.1	Issue applies to a plant feature, cooling ponds or cooling towers, which DCPP does not have.
Aquatic Ecology (for all plants)			
14. Refurbishment impacts to aquatic resources	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
15. Accumulation of contaminants in sediments or biota	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
16. Entrainment of phytoplankton and zooplankton	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
17. Cold shock	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
18. Thermal plume barrier to migrating fish	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
19. Distribution of aquatic organisms	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
20. Premature emergence of aquatic insects	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
21. Gas supersaturation (gas bubble disease)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
22. Low dissolved oxygen in the discharge	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
24. Stimulation of nuisance organisms (e.g., shipworms)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.

TABLE E-3
DCPP LICENSE RENEWAL NEPA ISSUES

Issue[a]	GEIS Category	Section of the Environmental Report	Relevance at DCPP/Environmental Impact
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)			
25. Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	4.2	**SMALL.** DCPP has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements.
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	4.3	**SMALL.** DCPP has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements.
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	4.4	**SMALL.** DCPP has a current NPDES permit which constitutes compliance with CWA Section 316(a) requirements.
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)			
28. Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	N/A	Issue applies to a heat dissipation system, cooling towers, which DCPP does not have.
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	N/A	Issue applies to a heat dissipation system, cooling towers, which DCPP does not have.
30. Heat shock for plants with cooling tower-based heat dissipation systems	1	N/A	Issue applies to a heat dissipation system, cooling towers, which DCPP does not have.
Groundwater Use and Quality			
31. Impacts of refurbishment on groundwater use and quality	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
32. Groundwater use conflicts (potable and service water; plants that use <100 gpm)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.

TABLE E-3
DCPP LICENSE RENEWAL NEPA ISSUES

Issue[a]	**GEIS Category**	**Section of the Environmental Report**	**Relevance at DCPP/Environmental Impact**
33. Groundwater use conflicts (potable, service water, and dewatering; plants that use >100 gpm)	2	NA, and discussed in Section 4.5	**SMALL.** DCPP does not withdraw groundwater at an average rate greater than 100 gpm.
34. Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	NA, and discussed in Section 4.6	Issue applies to a plant feature, cooling towers, which DCPP does not have.
35. Groundwater use conflicts (Ranney wells)	2	NA, and discussed in Section 4.7	Issue applies to a plant with Ranney Wells, which DCPP does not have.
36. Groundwater quality degradation (Ranney wells)	1	N/A	Issue applies to a plant with Ranney Wells, which DCPP does not have.
37. Groundwater quality degradation (saltwater intrusion)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
38. Groundwater quality degradation (cooling ponds in salt marshes)	1	N/A	Issue applies to a feature, cooling ponds, which DCPP does not have.
39. Groundwater quality degradation (cooling ponds at inland sites)	2	NA, and discussed in Section 4.8	Issue applies to a feature, cooling ponds, which DCPP does not have.
Terrestrial Resources			
40. Refurbishment impacts to terrestrial resources	2	NA, and discussed in Section 4.9	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
41. Cooling tower impacts on crops and ornamental vegetation	1	N/A	Issue applies to a plant feature, cooling towers, which DCPP does not have.
42. Cooling tower impacts on native plants	1	N/A	Issue applies to a plant feature, cooling towers, which DCPP does not have.
43. Bird collisions with cooling towers	1	N/A	Issue applies to a plant feature, cooling towers, which DCPP does not have.

TABLE E-3
DCPP LICENSE RENEWAL NEPA ISSUES

Issue[a]	GEIS Category	Section of the Environmental Report	Relevance at DCPP/Environmental Impact
44. Cooling pond impacts on terrestrial resources	1	N/A	Issue applies to a feature, cooling ponds, which DCPP does not have.
45. Power line right-of-way management (cutting and herbicide application)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
46. Bird collisions with power lines	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
48. Floodplains and wetlands on power line right-of-way	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
Threatened or Endangered Species (for all plants)			
49. Threatened or endangered species	2	4.10	**SMALL.** No effects on any state- or federally-listed or other special status plant or animal species, including designated critical habitat, are anticipated as a result of extending the operating license. PG&E does not plan to alter current operations over the period of extended operation.
Air Quality			
50. Air quality during refurbishment (non-attainment and maintenance areas)	2	NA, and discussed in Section 4.11	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
51. Air quality effects of transmission lines	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
Land Use			
52. Onsite land use	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.

TABLE E-3
DCPP LICENSE RENEWAL NEPA ISSUES

Issue[a]	GEIS Category	Section of the Environmental Report	Relevance at DCPP/Environmental Impact
53. Power line right-of-way land use impacts	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
Human Health			
54. Radiation exposures to the public during refurbishment	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
55. Occupational radiation exposures during refurbishment	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
56. Microbiological organisms (occupational health)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
57. Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	NA, and discussed in Section 4.12	Issue applies to plant features, cooling lakes, canals or towers, which DCPP does not have.
58. Noise	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
59. Electromagnetic fields, acute effects	2	4.13	**SMALL**. The largest modeled induced current under the DCPP lines is less than the 5-milliampere limit. Therefore, the DCPP transmission lines conform to the National Electrical Safety Code provisions for preventing electric shock from induced current.
60. Electromagnetic fields, chronic effects	N/A	4 Introduction	UNCERTAIN. Scientific evidence on the chronic biological effects on humans from exposure to transmission line electric and magnetic fields is inconclusive.
61. Radiation exposures to public (license renewal term)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.

TABLE E-3
DCPP LICENSE RENEWAL NEPA ISSUES

Issue[a]	GEIS Category	Section of the Environmental Report	Relevance at DCPP/Environmental Impact
62. Occupational radiation exposures (license renewal term)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
Socioeconomics			
63. Housing impacts	2	4.14	**SMALL.** For the purpose of license renewal, DCPP does not plan on any refurbishment and does not plan to add employees. Therefore, there will be no increased demand on housing because of license renewal.
64. Public services: public safety, social services, and tourism and recreation	1	4 Introduction	Refurbishment Not applicable to DCPP because issue applies to an activity that DCPP does not plan to undertake. Renewal Term Issue determined to have **SMALL** impact by GEIS.
65. Public services: public utilities	2	4.15	**SMALL.** For the purpose of license renewal, DCPP does not plan on any refurbishment and does not plan to add employees. Therefore, there will be no increased demand on public utilities because of license renewal.
66. Public services: education (refurbishment)	2	NA, and discussed in Section 4.16	Issue applies to an activity, refurbishment, which DCPP does not plan to undertake.
67. Public services: education (license renewal term)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
68. Offsite land use (refurbishment)	2	NA, and discussed in Section 4.17.1	Issue applies to an activity, refurbishment, which DCPP does not plan to undertake.

TABLE E-3
DCPP LICENSE RENEWAL NEPA ISSUES

Issue[a]	**GEIS Category**	**Section of the Environmental Report**	**Relevance at DCPP/Environmental Impact**
69. Offsite land use (license renewal term)	2	4.17.2	**SMALL.** Although taxes paid by the plant constitute a large fraction of the county revenue, the county has not shown significant offsite land use change since DCPP construction. No plant-induced changes to offsite land use are expected from license renewal. Therefore, continued operation is expected to have positive impacts.
70. Public services: transportation	2	4.18	**SMALL.** For the purpose of license renewal, DCPP does not plan on any refurbishment and does not plan to add employees. Therefore, there will be no increased demand on local transportation because of license renewal.
71. Historic and archaeological resources	2	4.19	**SMALL.** DCPP does not plan on any refurbishment or transmission-line corridor changes during the license renewal term. Continued plant site operations are not expected to impact cultural resources.
72. Aesthetic impacts (refurbishment)	1	N/A	Issue applies to an activity, refurbishment, which DCPP has no plans to undertake.
73. Aesthetic impacts (license renewal term)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
74. Aesthetic impacts of transmission lines (license renewal term)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.

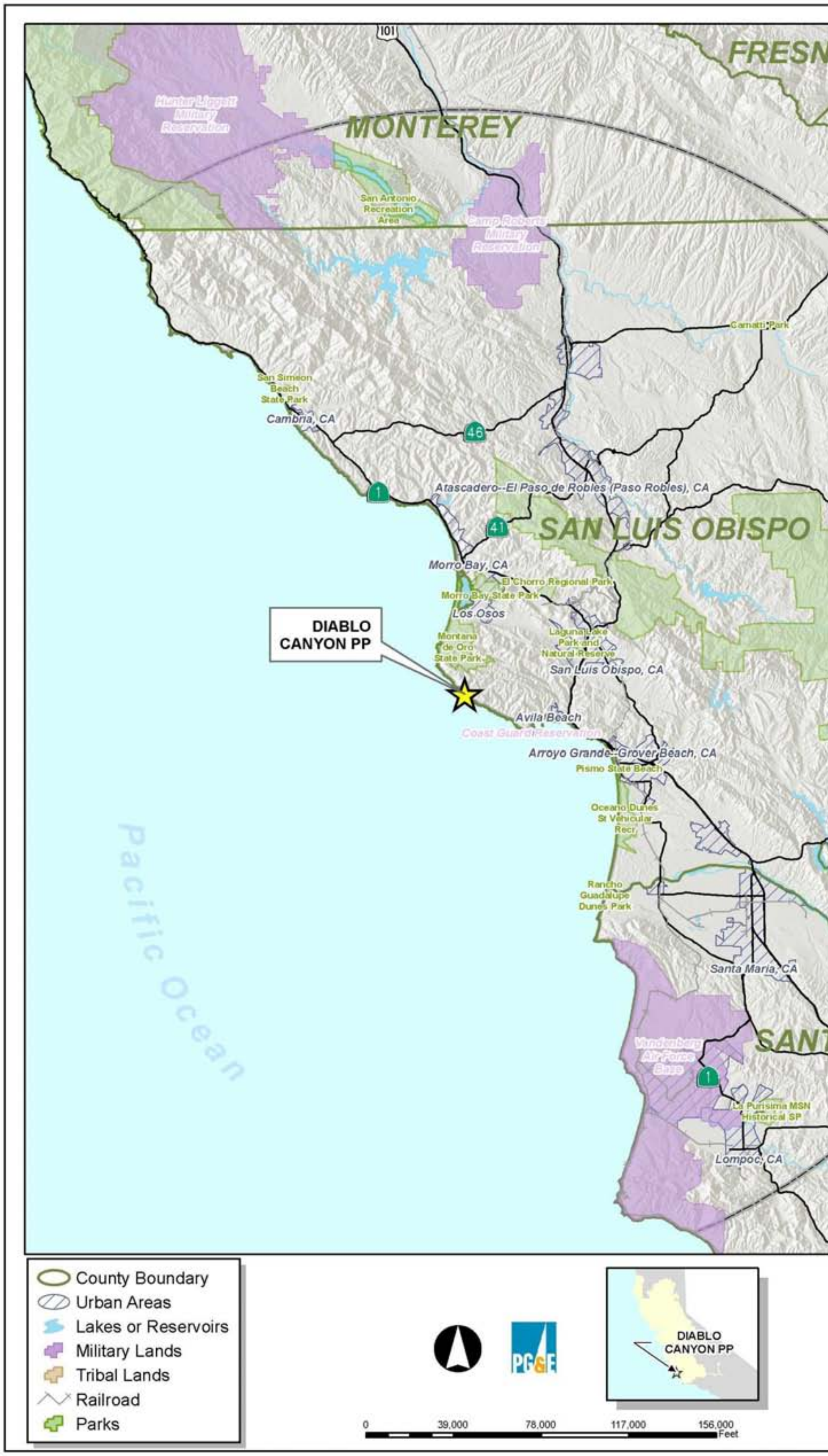
TABLE E-3
DCPP LICENSE RENEWAL NEPA ISSUES

Issue[a]	GEIS Category	Section of the Environmental Report	Relevance at DCPP/Environmental Impact
Postulated Accidents			
75. Design basis accidents	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
76. Severe accidents	2	4.20	**SMALL.** The benefit/cost analysis did not identify any cost-effective aging-related severe accident mitigation alternatives.
Uranium Fuel Cycle and Waste Management			
77. Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
78. Offsite radiological impacts (collective effects)	1	4 Introduction	Not in GEIS.
79. Offsite radiological impacts (spent fuel and high-level waste disposal)	1	4 Introduction	Not in GEIS.
80. Nonradiological impacts of the uranium fuel cycle	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
81. Low-level waste storage and disposal	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
82. Mixed waste storage and disposal	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
83. Onsite spent fuel	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
84. Nonradiological waste	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
85. Transportation	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
Decommissioning			
86. Radiation doses (decommissioning)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.

TABLE E-3
DCPP LICENSE RENEWAL NEPA ISSUES

Issue[a]	GEIS Category	Section of the Environmental Report	Relevance at DCPP/Environmental Impact
87. Waste management (decommissioning)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
88. Air quality (decommissioning)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
89. Water quality (decommissioning)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
90. Ecological resources (decommissioning)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
91. Socioeconomic impacts (decommissioning)	1	4 Introduction	Issue determined to have **SMALL** impact by GEIS.
Environmental Justice			
92. Environmental justice	N/A	2.6.2	NONE. The need for and content of an analysis of environmental justice will be addressed in plant-specific reviews.

a. Source: 10 CFR 51, Subpart A, Appendix A, Table B-1. (Issue numbers added to facilitate discussion.)
b. Source: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437).



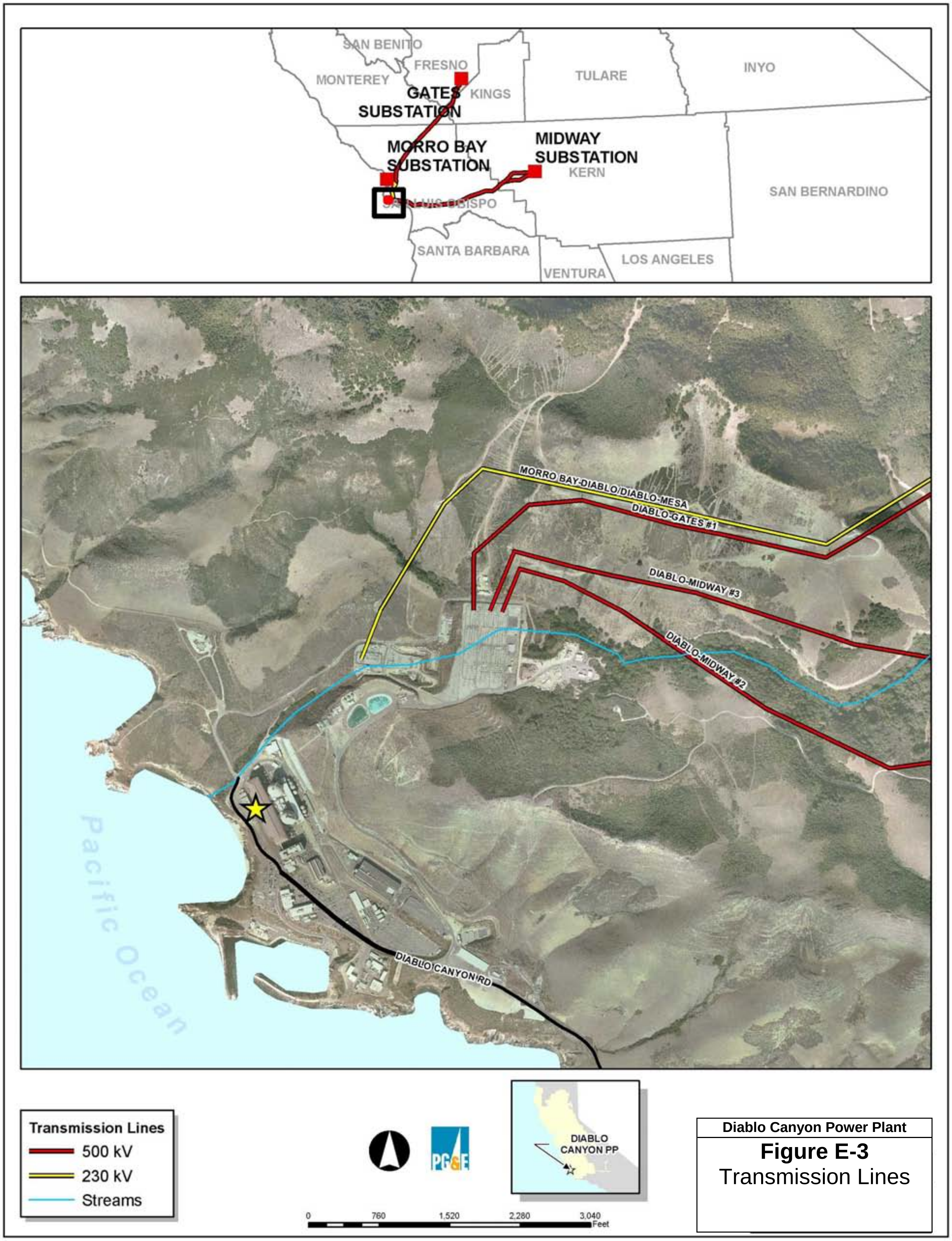
Diablo Canyon Power Plant

Figure E-1

50-Mile Vicinity Map

Diablo Canyon Power Plant

Figure E-2
6-Mile Vicinity Map



Diablo Canyon Power Plant
Figure E-3
Transmission Lines


Montaña de Oro State Park
Pacific Gas and Electric Company
PG&E
POINT BUCHON TRAIL
Diablo Canyon Power Plant
Point Buchon Trail
Pecho Valley Road
Coon Creek Beach
Northern Gate
Coon Creek Parking Lot
Trail Check-In Station
Point Buchon
Montaña de Oro State Park
Pecho Valley Road
Disney/Fat Point
Big Wash
Pecho Valley Road
Tom's Pond
Windy Point
Barn Road
Trail Terminus and Turn-around Point
Diablo Canyon Power Plant
Figure E-4
Point Buchon Trail Map
Trail System
Existing Trail
Route Markers
Vista Points
Beach Access
PG&E Property Boundary
N
W
E
S
0
0.25
0.5 Mile
Source: USGS 10m DEM (40ft contours); SLO County (2003); PG&E (2005 - 2008)
LSA Associates, Inc. i:\pge534\gis\Public_Trail_System.mxd (2/11/2009)

Diablo Canyon Power Plant

Figure E-5

Pecho Coast Trail Map

ATTACHMENT E-1

California Coastal Management Program's
California Coastal Policies

The California Coastal Management Program (CCMP) policies are contained in Division 20, Chapter 3 of the California Public Resource Code and require persons seeking approval for activities which may impact the Coastal Zone to demonstrate that the activity is consistent with all enforceable policies in Division 20, Chapter 3 of the California Public Resource Code. PG&E is seeking renewal of the operating licenses for DCPP Units 1 and 2. The following sections detail the CCMP policies (listed in italics) and provide PG&E's demonstration that DCPP license renewal would be consistent with policies contained in Division 20, Chapter 3 of the California Public Resource Code.

I. General

<u>Section 30200 – Policies as standards; resolution of policy conflicts</u>

Requirements:
(a) Consistent with the coastal zone values cited in Section 30001 and the basic goals set forth in Section 30001.5, and except as may be otherwise specifically provided in this division, the policies of this chapter shall constitute the standards by which the adequacy of local coastal programs, as provided in Chapter 6 (commencing with Section 30500), and, the permissibility of proposed developments subject to the provisions of this division are determined. All public agencies carrying out or supporting activities outside the coastal zone that could have a direct impact on resources within the coastal zone shall consider the effect of such actions on coastal zone resources in order to assure that these policies are achieved.

(b) Where the commission or any local government in implementing the provisions of this division identifies a conflict between the policies of this chapter, Section 30007.5 shall be utilized to resolve the conflict and the resolution of such conflicts shall be supported by appropriate findings setting forth the basis for the resolution of identified policy conflicts.

DCPP Response:
(a) DCPP is an existing, developed site; it's location and operations will remain unchanged. As such, license renewal does not create a conflict between the CCR policies of protecting coastal resources and permitting proposed developments.
(b) PG&E is aware of no negative impacts that continued operations would have on valuable coastal resources areas. As stated in ER Sections 2.6, 2.7, and 2.8, DCPP's license renewal will have a continued significant positive impact on the economic and social interest of California State from contributions to the tax base, education funding, support of public services infrastructure, and workforce.

II. Public Access

Section 30210 – Access; recreational opportunities; posting

Requirements:
In carrying out the requirement of Section 4 of Article X of the California Constitution, maximum access, which shall be conspicuously posted, and recreational opportunities shall be provided for all the people consistent with public safety needs and the need to protect public rights, rights of private property owners, and natural resource areas from overuse.

DCPP Response:
Heightened security concerns since September 11, 2001, precludes access to the coast in front of the power plant as well as the recreational use of DCPP's waterfront and other property by the general public. These national security concerns likely will preclude such uses until the plant is decommissioned and all used fuel has been removed from the site.

License renewal is consistent with Section 30210 of the Coastal Act requiring maintenance of maximum coastal access and recreational opportunities because PG&E will continue to support public access to the Pecho Coast Trail (Figure E-5), the Point San Luis Lighthouse, and the Point Buchon Trail (Figure E-4), as required by coastal development permits issued by the California Coastal Commission. Public access supported by PG&E includes docent-led hikes on the Pecho Coast trail and to the Point San Luis Lighthouse on the South Ranch, funding for County projects to enhance access to the lighthouse, a program that brings inner-city children to the DCPP site for educational tours, and the creation and maintenance of the 7-mile Point Buchon Trail on the North Ranch, adjacent to Montana De Oro State Park.

PG&E is dedicated to maintaining and protecting the natural, historical and archaeological resources on PG&E-owned property, while also protecting public safety.

Section 30211 – Development not to interfere with access

Requirements:
Development shall not interfere with the public's right of access to the sea where acquired through use or legislative authorization, including the use of dry sand and rocky coastal beaches to the first line of terrestrial vegetation.

DCPP Response:
Heightened security concerns since September 11, 2001, precludes access to the coast in front of the power plant as well as the recreational use of DCPP's waterfront and other property by the general public. These national security concerns likely will preclude such uses until the plant is decommissioned and all used fuel has been removed from the site.

License renewal is consistent with Section 30211 of the Coastal Act requiring preservation of the public's access to the sea, including the use of dry sand and rocky coastal beaches to the first line of terrestrial vegetation by preserving existing coastal recreation and beach access trails. In 2007, PG&E developed the Point Buchon Trail for public use (Figure E-4). This trail winds its way through the many varieties of terrestrial vegetation along the Pacific coastal bluffs and allows direct public access to the rocky coast and beaches along the 7-mile trail. The trail and its availability to the public will not be affected by license renewal. Additionally, license renewal will not interfere with the public's use of vicinity beaches in any way.

<u>Section 30212 – New development projects</u>

Requirements:
(a) Public access from the nearest public roadway to the shoreline and along the coast shall be provided in new development projects except where: (1) It is inconsistent with public safety, military security needs, or the protection of fragile coastal resources, (2) Adequate access exists nearby, or, (3) Agriculture would be adversely affected. Dedicated accessway shall not be required to be opened to public use until a public agency or private association agrees to accept responsibility for maintenance and liability of the accessway.

(b) For purposes of this section, "new development" does not include:

> *(1) Replacement of any structure pursuant to the provisions of subdivision (g) of Section 30610.*
> *(2) The demolition and reconstruction of a single-family residence; provided, that the reconstructed residence shall not exceed either the floor area, height or bulk of the former structure by more than 10 percent, and that the reconstructed residence shall be sited in the same location on the affected property as the former structure.*
> *(3) Improvements to any structure which do not change the intensity of its use, which do not increase either the floor area, height, or bulk of the structure by more than 10 percent, which do not block or impede public access, and which do not result in a seaward encroachment by the structure.*
> *(4) The reconstruction or repair of any seawall; provided, however, that the reconstructed or repaired seawall is not a seaward of the location of the former structure.*
> *(5) Any repair or maintenance activity for which the commission has determined, pursuant to Section 30610, that a coastal development permit will be required unless the commission determines that the activity will have an adverse impact on lateral public access along the beach.*

As used in this subdivision "bulk" means total interior cubic volume as measured from the exterior surface of the structure.

(c) Nothing in this division shall restrict public access nor shall it excuse the performance of duties and responsibilities of public agencies which are required by Sections 66478.1 to 66478.14, inclusive, of the Government Code and by Section 4 of Article X of the California Constitution.

DCPP Response:
License renewal is not a new development, but a continuation of existing development. Heightened security concerns since September 11, 2001, precludes access to the coast in front of the power plant as well as the recreational use of DCPP's waterfront and other property by the general public. These national security concerns likely will preclude such uses until the plant is decommissioned and all used fuel has been removed from the site.

<u>Section 30212.5 – Public facilities; distribution</u>

Requirements:
Wherever appropriate and feasible, public facilities, including parking areas or facilities, shall be distributed throughout the area so as to mitigate against the impacts, social or otherwise, of overcrowding or overuse by the public of any single area.

DCPP Response:
Due to national security concerns, there are no public facilities available on PG&E-owned land. Public facilities and parking supporting public access to the Point Buchon Trail and the coastline along the trail are located in Montana De Oro State Park. Public facilities and parking supporting public access to the Pecho Coast Trail and the Point San Luis Lighthouse are located on property adjacent to DCPP owned by the San Luis Obispo Harbor District.

License renewal is consistent with Section 30212.5 of the Coastal Act because it will preserve existing public use of recreational and beach access trails.

<u>Section 30213 – Lower cost visitor and recreational facilities; encouragement and provision, overnight room rentals</u>
Requirements:
Lower cost visitor and recreational facilities shall be protected, encouraged, and, where feasible, provided. Developments providing public recreational opportunities are preferred.

The commission shall not: (1) require that overnight room rentals be fixed at an amount certain for any privately owned and operated hotel, motel, or other similar visitor-serving facility located on either public or private lands; or (2) establish or approve any method for the identification of low or moderate income persons for the purpose of determining eligibility for overnight room rentals in any such facilities.

DCPP Response:
Due to national security concerns, there are no public facilities available on PG&E-owned land. Public facilities and parking supporting public access to the Point Buchon Trail are located in Montana De Oro State Park. Public facilities and parking supporting public access to the Pecho Coast Trail and the Point San Luis Lighthouse are located on property adjacent to DCPP owned by the San Luis Obispo Harbor District.

License renewal is consistent with Section 30213 of the Coastal Act because it will preserve existing free public use of recreational and beach access trails.

<u>Section 30214 – Implementation of public access policies; legislative intent</u>

Requirements:
(a) The public access policies of this article shall be implemented in a manner that takes into account the need to regulate the time, place, and manner of public access depending on the facts and circumstances in each case including, but not limited to, the following:

(1) Topographic and geologic site characteristics.
(2) The capacity of the site to sustain use and at what level of intensity.
(3) The appropriateness of limiting public access to the right to pass and repass depending on such factors as the fragility of the natural resources in the area and the proximity of the access area to adjacent residential uses.
(4) The need to provide for the management of access areas so as to protect the privacy of adjacent property owners and to protect the aesthetic values of the area by providing for the collection of litter.

(b) It is the intent of the Legislature that the public access policies of this article be carried out in a reasonable manner that considers the equities and that balances the rights of the individual property owner with the public's constitutional right of access pursuant to Section 4 of Article X of the California Constitution. Nothing in this section or any amendment thereto shall be construed as a limitation on the rights guaranteed to the public under Section 4 of Article X of the California Constitution.

(c) In carrying out the public access policies of this article, the commission and any other responsible public agency shall consider and encourage the utilization of innovative access management techniques, including, but not limited to, agreements with private organizations which would minimize management costs and encourage the use of volunteer programs.

DCPP Response:
License renewal is consistent with Section 30214 of the Coastal Act requiring that public access be implemented in a manner that preserves the site and natural resources because no new direct public access to open space or other coastal resources will be created by license renewal. Additionally, DCPP is not directly

adjacent to private property owners within the coastal zone and, therefore, license renewal will not negatively impact the privacy of property owners.

PG&E is dedicated to maintaining and protecting the natural, historical and archaeological resources on PG&E-owned property, while also protecting public safety.

III. Recreation

<u>Section 30220 – Protection of certain water-oriented activities</u>

Requirements:
Coastal areas suited for water-oriented recreational activities that cannot readily be provided at inland water areas shall be protected for such uses.

DCPP Response:
Heightened security concerns since September 11, 2001, preclude access to the coast in front of the power plant as well as the recreational use of DCPP's waterfront and other property by the general public. These national security concerns likely will preclude such uses until the plant is decommissioned and all used fuel has been removed from the site.

License renewal is consistent with Section 30220 of the Coastal Act requiring the protection of water-oriented recreational activities because it will not interfere with the recreational water activities at the adjacent San Luis Obispo Harbor District and nearby Avila Beach community.

<u>Section 30221 – Oceanfront land; protection for recreational use and development</u>

Requirements:
Oceanfront land suitable for recreational use shall be protected for recreational use and development unless present and foreseeable future demand for public or commercial recreational activities that could be accommodated on the property is already adequately provided for in the area.

DCPP Response:
Heightened security concerns since September 11, 2001, preclude access to the coast in front of the power plant as well as the recreational use of DCPP's waterfront and other property by the general public. These national security concerns likely will preclude such uses until the plant is decommissioned and all used fuel has been removed from the site.

License renewal is consistent with Section 30221 of the Coastal Act requiring the protection of oceanfront land suitable for recreational use because present and foreseeable future demand for public or commercial recreational oceanfront activities is adequately provided for by Montana De Oro State Park, the San Luis Obispo Harbor District, and the nearby communities of Avila Beach, Shell Beach and Pismo Beach.

<u>Section 30222 – Private lands; priority of development purposes</u>

Requirements:
The use of private lands suitable for visitor-serving commercial recreational facilities designed to enhance public opportunities for coastal recreation shall have priority over private residential, general industrial, or general commercial development, but not over agriculture or coastal-dependent industry.

DCPP Response:
This policy is not applicable to consistency review of the license renewal project as DCPP is an existing facility.

<u>Section 30222.5 – Oceanfront land; protection for aquaculture use and development</u>

Requirements:
Oceanfront land that is suitable for coastal dependent aquaculture shall be protected for that use, and proposals for aquaculture facilities located on those sites shall be given priority, except over the coastal dependent developments or uses.

DCPP Response:
This policy is not applicable to consistency review of the license renewal project as DCPP is an existing facility.

Heightened security concerns since September 11, 2001, preclude access to the coast in front of the power plant as well as the recreational use of DCPPs waterfront and other property by the general public. These national security concerns likely will preclude such uses until the plant is decommissioned and all used fuel has been removed from the site.

<u>Section 30223 – Upland areas</u>
Requirements:
Uplands necessary to support coastal recreational uses shall be reserved for such uses, where feasible.

DCPP Response:
Heightened security concerns since September 11, 2001, preclude access to the coast in front of the power plant as well as the recreational use of DCPP's waterfront and other property by the general public. These national security concerns likely will preclude such uses until the plant is decommissioned and all used fuel has been removed from the site.

License renewal is consistent with Section 30223 of the Coastal Act because it will not interfere with the recreational use of the coastline in the nearby oceanfront communities.

<u>Section 30224 – Recreational boating use; encouragement; facilities</u>

Requirements:
Increased recreational boating use of coastal waters shall be encouraged, in accordance with this division, by developing dry storage areas, increasing public launching facilities, providing additional berthing space in existing harbors, limiting non-water-dependent land uses that congest access corridors and preclude boating support facilities, providing harbors of refuge, and by providing for new boating facilities.

DCPP Response:
Heightened security concerns since September 11, 2001, preclude access to the coast in front of the power plant as well as the recreational use of DCPP's waterfront and other property by the general public. These national security concerns likely will preclude such uses until the plant is decommissioned and all used fuel has been removed from the site.

License renewal is consistent with Section 30224 of the Coastal Act because it will not interfere with recreational boating use allowed by the San Luis Obispo Harbor District and consistent with national security.

IV. Marine Environment

<u>Section 30230 – Marine resources; maintenance</u>

Requirements:
Marine resources shall be maintained, enhanced, and where feasible, restored. Special protection shall be given to areas and species of special biological or economic significance. Uses of the marine environment shall be carried out in a manner that will sustain the biological productivity of coastal water and that will maintain healthy populations of all species of marine organisms adequate for long-term commercial, recreational, scientific, and educational purposes.

DCPP Response:
As explained in more detail below, license renewal is consistent with Section 30230 of the Coastal Act because the results of extensive ecological studies conducted during the current operating license period demonstrate that losses of marine organism larvae and/or eggs as a result of entrainment, impingement, or heat shock resulting from use of a once-through cooling system at DCPP do not result in observable population level impacts.

Once-through cooling entrainment, impingement, and thermal impacts are not significantly changing or increasing, and the protection of the beneficial uses of the receiving water will continue during the license renewal period.

According to the California Department of Fish and Game (CDF&G), DCPP is not located in a Marine Protection Area (MPA). The Point Buchon State Marine Preserve, however, is located along the northern coast of PG&E-owned land. As discussed in ER sections 2.2, 2.5, and 4.10, there are several threatened or endangered aquatic species on PG&E-owned property and transmission line corridors. However, PG&E is currently unaware of any adverse issues that involve threatened or endangered species associated with the operation and/or maintenance of DCPP, including the existing transmission lines, towers, and access roads.

PG&E provides the current, enforceable, DCPP NPDES Permit No, CA0003751, Order 90-09, as evidence of Water Quality Certification under Clean Water Act (CWA) Section 401 (CCRWQCB 1990) (refer to ER Attachment B). The permit was due to expire in 1995, and has since been in administrative extension. DCPP is actively working with the Central Coast Regional Water Quality Control Board (CCRWQCB) to renew the permit.

As discussed in ER Section 4.2, the current NPDES Permit does not include any requirements for ongoing entrainment monitoring during power plant intake operations. Based on evidence from the extensive ecological studies conducted during the initial operating license period, entrainment losses of marine organism larvae and/or eggs do not result in observable population level impacts, and subsequently observable detrimental impacts to the overall ecological system susceptible to influence by cooling system withdrawal. Therefore, entrainment impacts to marine fish and shellfish resources from operation of the power plant once-through cooling system during the period of extended operation are projected to be SMALL.

As discussed in ER Section 4.3, the current NPDES permit does not include any requirements for ongoing impingement monitoring during plant intake operations. Based on the determination of impacts during the initial operating license period, PG&E concludes that impingement impacts to fish and shellfish resources from operation of the once-through cooling system during the period of extended operation are projected to be SMALL.

As discussed in ER Section 4.4, in accordance with NPDES Permit requirements, DCPP monitors discharge characteristics (including heat shock) and reports the results to the CCRWQCB. Continued monitoring of the marine environment influenced by the power plant discharge is anticipated to support previous conclusions regarding thermal impacts. Once-through cooling system thermal effects are not significantly changing or increasing, and protection of the beneficial uses of the receiving water will continue in the period of extended operation. PG&E concludes that heat shock impacts to fish and shellfish resources from operation of the once-through cooling system during the period of extended operation, relative to the determinations of thermal discharge impacts during the initial operating license period, are projected to be SMALL.

<u>Section 30231 – Biological productivity; water quality</u>

Requirements:

The biological productivity and the quality of coastal waters, streams, wetlands, estuaries, and lakes appropriate to maintain optimum populations of marine organisms and for the protection of human health shall be maintained and, where feasible, restored through, among other means, minimizing adverse effects of waste water discharges and entrainment, controlling runoff, preventing depletion of ground water supplies and substantial interference with surface water flow, encouraging waste water reclamation, maintaining natural vegetation buffer areas that protect riparian habitats, and minimizing alteration of natural streams.

DCPP Response:
License renewal is consistent with Section 30231 of the Coastal Act because existing operations will remain unchanged and will be governed by a wastewater discharge permit, as are current operations at the plant.

Wastewater discharges are governed by the NPDES Permit No. CA0003751, Order 90-09. DCPP is in compliance with this current enforceable permit, and does not foresee any changes in the operation of the once-through cooling system as a result of the proposed action.

As described in ER Section 2.3, DCPP groundwater use is limited to the periodic draw of freshwater supply from an onsite deep well. The groundwater source is geologically isolated to the Diablo Canyon watershed, and is therefore not hydraulically connected to other area groundwater resources. The surface streambed of Diablo Creek is not used as a freshwater supply resource. Groundwater is used only as required to supplement supply of the on-site Raw Water Storage Reservoirs which feeds the emergency firewater, plant site domestic water, and power production make-up water systems. The primary source of freshwater for power plant operations is seawater reverse osmosis. Uses of groundwater will not change as a result of the proposed action.

No changes to natural vegetation buffer areas or natural streams will be conducted as part of the proposed action.

The quality of effluents from plant operations are controlled under DCPP's NPDES Permit (Cal-EPA No. CA0003751) in order to minimize any potential adverse impacts to surface waters. Liquid radioactive effluents are monitored in accordance with NRC regulations, policies, and guidance through existing plant procedures. DCPP liquid radioactive effluents are well below NRC limits. No changes to effluent controls and monitoring will result from the proposed action.

<u>Section 30232 – Oil and hazardous substance spills</u>

Requirements:
Protection against the spillage of crude oil, gas, petroleum products, or hazardous substances shall be provided in relation to any development or transportation of such materials. Effective containment and cleanup facilities and procedures shall be provided for accidental spills that do occur.

DCPP Response:
License renewal is consistent with Section 30232 of the Coastal Act because DCPP has developed and implements operating procedures to ensure that oil and hazardous substances used on site are safely handled and stored. The power plant also maintains appropriate registrations or licenses as required related to the management of hazardous substances (Hazardous Waste Facility Permit, EPA ID Number CAD077966349, UST Operating Permit 40-000-17604-006) as well as process specific procedures to prevent spills and releases from operating and storage equipment associated with those authorizations. This includes a certified Spill Prevention, Control, and Countermeasures (SPCC) Plan, as required by 40 CFR 112, to prevent the discharge of oil to surface waters or surface water tributaries. The SPCC will continue to be utilized throughout the period of extended operation. In the event of an oil or hazardous substance spill, contingency emergency response procedures are implemented to effect rapid response and clean-up, as well as mitigate potential hazards to human health or the environment (CP-M-9A Hazardous Materials Incident - Initial Emergency Response/Mitigation Procedure). Plant operations and dedicated emergency response resources are provided continuously on-shift at the facility to respond to oil or hazardous materials incidents, and implement spill control contingency plans.

<u>Section 30233 – Diking, filling, or dredging continued movement of sediment and nutrients</u>

Requirements:
(a) The diking, filling, or dredging of open coastal waters, wetlands, estuaries, and lakes shall be permitted in accordance with other applicable provisions of this division, where there is no feasible less environmentally damaging alternative, and where feasible mitigation measures have been provided to minimize adverse environmental effects, and shall be limited to the following:

> *(l) New or expanded port, energy, and coastal-dependent industrial facilities, including commercial fishing facilities.*
> *(2) Maintaining existing, or restoring previously dredged, depths in existing navigational channels, turning basins, vessel berthing and mooring areas, and boat launching ramps.*
> *(3) In open coastal waters, other than wetlands, including streams, estuaries, and lakes, new or expanded boating facilities and the placement of structural pilings for public recreational piers that provide public access and recreational opportunities.*
> *(4) Incidental public service purposes, including but not limited to, burying cables and pipes or inspection of piers and maintenance of existing intake and outfall lines.*
> *(5) Mineral extraction, including sand for restoring beaches, except in environmentally sensitive areas.*
> *(6) Restoration purposes.*
> *(7) Nature study, aquaculture, or similar resource dependent activities.*

(b) Dredging and spoils disposal shall be planned and carried out to avoid significant disruption to marine and wildlife habitats and water circulation. Dredge spoils suitable for beach replenishment should be transported for these purposes to appropriate beaches or into suitable longshore current systems.

(c) In addition to the other provisions of this section, diking, filling, or dredging in existing estuaries and wetlands shall maintain or enhance the functional capacity of the wetland or estuary. Any alteration of coastal wetlands identified by the Department of Fish and Game, including, but not limited to, the 19 coastal wetlands identified in its report entitled, "Acquisition Priorities for the Coastal Wetlands of California", shall be limited to very minor incidental public facilities, restorative measures, nature study, commercial fishing facilities in Bodega Bay, and development in already developed parts of south San Diego Bay, if otherwise in accordance with this division.

For the purposes of this section, "commercial fishing facilities in Bodega Bay" means that not less than 80 percent of all boating facilities proposed to be developed or improved, where such improvement would create additional berths in Bodega Bay, shall be designed and used for commercial fishing activities.

(d) Erosion control and flood control facilities constructed on watercourses can impede the movement of sediment and nutrients that would otherwise be carried by storm runoff into coastal waters. To facilitate the continued delivery of these sediments to the littoral zone, whenever feasible, the material removed from these facilities may be placed at appropriate points on the shoreline in accordance with other applicable provisions of this division, where feasible mitigation measures have been provided to minimize adverse environmental effects. Aspects that shall be considered before issuing a coastal development permit for these purposes are the method of placement, time of year of placement, and sensitivity of the placement area.

DCPP Response:
Section 30233 of the Coastal Act is not applicable to license renewal because the project will not include any of the listed activities or impacts. Specifically, DCPP has no specific plans for diking, filling, or dredging of open coastal waters, wetlands, estuaries, or lakes as a part of the proposed action. However, it is possible during the period of extended operation that sediment removal could be required at some time to maintain operability of the facility ocean water intake structure. Silt and sand has the potential to build to detrimental levels through natural environmental processes within the power plants existing engineered intake cove. Deposition and/or depletion of benthic sediments occur due to wave and tidal actions in the exposed coastal area. Excessive sediment buildup in the mouth of the intake cove, or directly in front of the intake structure, could necessitate precautionary dredging removal. It is anticipated that any such effort would be limited to the existing 80-meter square exclusion zone immediately in

front of the intake structure opening. If required, dredging operations and associated spoils placement would only be conducted following planning and permitted in accordance with all requirements of the U.S. Army Corp of Engineers and associated State Agencies.

As intake cove sediments dredging is only a hypothetical requirement, and if implemented during the period of extended operation would most likely be confined to the existing plant intake exclusion zone, it is expected that there would be no significant disruption to marine and wildlife habitats or water circulation as a result of the proposed action.

<u>Section 30234 – Commercial fishing and recreational boating facilities</u>
Requirements:
Facilities serving the commercial fishing and recreational boating industries shall be protected and, where feasible, upgraded. Existing commercial fishing and recreational boating harbor space shall not be reduced unless the demand for those facilities no longer exists or adequate substitute space has been provided. Proposed recreational boating facilities shall, where feasible, be designed and located in such a fashion as not to interfere with the needs of the commercial fishing industry.

DCPP Response:
Section 30234 of the Coastal Act is not applicable to consistency review of license renewal because there are no boating or fishing industries in the area.

<u>Section 30234.5 – Economic, commercial, and recreational importance of fishing</u>
Requirements:
The economic, commercial, and recreational importance of fishing activities shall be recognized and protected.

DCPP Response:
Section 30234.5 of the Coastal Act is not applicable to consistency review of license renewal because there are no boating or fishing industries in the area.

<u>Section 30235 – Construction altering natural shoreline</u>
Requirements:
Revetents, breakwaters, groins, harbor channels, seawalls, cliff retaining walls, and other such construction that alters natural shoreline processes shall be permitted when required to serve coastal-dependent uses or to protect existing structures or public beaches in danger from erosion, and when designed to eliminate or mitigate adverse impacts on local shoreline sand supply. Existing marine structures causing water stagnation contributing to pollution problems and fish kills should be phased out or upgraded where feasible.

DCPP Response:
Section 30235 of the Coastal Act is not applicable to consistency review of license renewal because the project will not include any construction altering the shoreline and there are no existing structures causing water stagnation.

Section 30236 – Water supply and flood control

Requirements:
Channelizations, dams, or other substantial alterations of rivers and streams shall incorporate the best mitigation measures feasible, and be limited to (1) necessary water supply projects, (2) flood control projects where no other method for protecting existing structures in the floodplains is feasible and where such protection is necessary for public safety or to protect existing development, or (3) developments where the primary function is the improvement of fish and wildlife habitat.

DCPP Response:
Section 30236 of the Coastal Act is not applicable to consistency review of license renewal because the additional years of operation will not involve any substantial alteration of rivers or streams.

V. Land Resources

Section 30240 – Environmentally sensitive habitat areas; adjacent developments

Requirements:
Environmentally sensitive habitat areas shall be protected against any significant disruption of habitat values, and only uses dependent on those resources shall be allowed within those areas.

Development in areas adjacent to environmentally sensitive habitat areas and parks and recreation areas shall be sited and designed to prevent impacts which would significantly degrade those areas, and shall be compatible with the continuance of those habitat and recreation areas.

DCPP Response:
License renewal is consistent with Section 30240 of the Coastal Act requiring the protection of environmentally sensitive habitat areas because current operations, land uses, and practices, which are consistent with protecting environmentally sensitive habitat areas, will be extended throughout the additional term of operations. For example, the Coastal Commission recently designated certain portions of land on either side of the access road to the plant as environmentally sensitive habitat areas; PG&E takes and will continue to take that designation into account when planning any project or other activity occurring in those areas.

Likewise, license renewal is compatible with continuance of the habitat and nearby recreational areas because operations, land uses, and practices will remain unchanged. PG&E has a positive and cooperative relationship with the adjacent Montana De Oro State Park, the only recreational area near the site, through which it shares responsibility for maintenance of the land and improvements on the property line between PG&E and Montana De Oro State Park.

<u>Section 30241 – Prime agricultural land; maintenance in agricultural production</u>

Requirements:
The maximum amount of prime agricultural land shall be maintained in agricultural production to assure the protection of the areas' agricultural economy, and conflicts shall be minimized between agricultural and urban land uses through all of the following:

- a *By establishing stable boundaries separating urban and rural areas, including, where necessary, clearly defined buffer areas to minimize conflicts between agricultural and urban land uses.*
- b *By limiting conversions of agricultural lands around the periphery of urban areas to the lands where the viability of existing agricultural use is already severely limited by conflicts with urban uses or where the conversion of the lands would complete a logical and viable neighborhood and contribute to the establishment of a stable limit to urban development.*
- c *By permitting the conversion of agricultural land surrounded by urban uses where the conversion of the land would be consistent with Section 30250.*
- d *By developing available lands not suited for agriculture prior to the conversion of agricultural lands.*
- e *By assuring that public service and facility expansions and nonagricultural development do not impair agricultural viability, either through increased assessment costs or degraded air and water quality.*
- f *By assuring that all divisions of prime agricultural lands, except those conversions approved pursuant to subdivision (b), and all development adjacent to prime agricultural lands shall not diminish the productivity of such prime agricultural lands.*

DCPP Response:
License renewal is consistent with Section 30241 of the Coastal Act requiring that the maximum amount of prime agricultural land be maintained in agricultural production because all of the acreage north and south of the power plant is leased to individuals who implement sustainable grazing and agricultural practices. Continued operations will not impact the agricultural uses of the property.

<u>Section 30241.5 – Agricultural lands; determination of viability of uses; economic feasibility evaluation</u>

Requirements:
If the viability of existing agricultural uses is an issue pursuant to subdivision (b) of Section 30241 as to any local coastal program or amendment to any certified local coastal program submitted for review and approval under this division, the

determination of "viability" shall include, but not be limited to, consideration of an economic feasibility evaluation containing at least both of the following elements:

a *An analysis of the gross revenue from the agricultural products grown in the area for the five years immediately preceding the date of the filing of a proposed local coastal program or an amendment to any local coastal program.*

b *An analysis of the operational expenses, excluding the cost of land, associated with the production of the agricultural products grown in the area for the five years immediately preceding the date of the filing of a proposed local coastal program or an amendment to any local coastal program.*

For purposes of this subdivision, "area" means a geographic area of sufficient size to provide an accurate evaluation of the economic feasibility of agricultural uses for those lands included in the local coastal program or in the proposed amendment to a certified local coastal program.

The economic feasibility evaluation required by subdivision (a) shall be submitted to the commission, by the local government, as part of its submittal of a local coastal program or an amendment to any local coastal program. If the local government determines that it does not have the staff with the necessary expertise to conduct the economic feasibility evaluation, the evaluation may be conducted under agreement with the local government by a consultant selected jointly by local government and the executive director of the commission.

DCPP Response:
All of the acreage north and south of the power plant is leased to individuals who implement sustainable grazing and agricultural practices. Continued operations will not impact the agricultural uses of the property. Thus, no economic feasibility evaluation is necessary.

<u>Section 30242 – Lands suitable for agricultural use; conversion</u>

Requirements:
All other lands suitable for agricultural use shall not be converted to nonagricultural uses unless (l) continued or renewed agricultural use is not feasible, or (2) such conversion would preserve prime agricultural land or concentrate development consistent with Section 30250. Any such permitted conversion shall be compatible with continued agricultural use on surrounding lands.

DCPP Response:
License renewal is consistent with Section 30242 of the Coastal Act requiring that lands suitable for agricultural use not be converted to nonagricultural uses because the additional years of operation will not impact or change current land use and land practices, including the agricultural uses of the property. (See response to Section 30241).

Section 30243:
Productivity of soils and timberlands; conversions
Requirements – The long-term productivity of soils and timberlands shall be protected, and conversions of coastal commercial timberlands in units of commercial size to other uses or their division into units of noncommercial size shall be limited to providing for necessary timber processing and related facilities.

DCPP Response:
License renewal is consistent with Section 30243 of the Coastal Act requiring protection of the long-term productivity of soils and timberlands because the additional years of operation will not impact or change the agricultural uses on the property. There are no commercial timberlands at or near DCPP.

Section 30244 – Archaeological or paleontological resources

Requirements:
Where development would adversely impact archaeological or paleontological resources as identified by the State Historic Preservation Officer, reasonable mitigation measures shall be required.

DCPP Response:
License renewal is consistent with Section 30244 of the Coastal Act requiring reasonable mitigation measures for any adverse impacts on archaeological or paleontological resources because, as described in ER Sections 2.11 and 4.19, the additional years of operation will not impact archaeological and paleontological resources.

An existing Archaeological Resources Management Plan, which was established to protect the archaeological resources located on CA-SLO-2, will continue to be utilized throughout the period of extended operation. CA-SLO-2 is registered with the State Historic Preservation Officer. As part of license renewal, PG&E will be developing a Programmatic Agreement and Historical Properties Management Plan for review by the State Historic Preservation Officer.

VI. Development

Section 30250 – Location, existing developed areas

Requirements:

(a) New residential, commercial, or industrial development, except as otherwise provided in this division, shall be located within, contiguous with, or in close proximity to, existing developed areas able to accommodate it or, where such areas are not able to accommodate it, in other areas with adequate public services and where it will not have significant adverse effects, either individually or cumulatively, on coastal resources. In addition, land divisions, other than leases for agricultural uses, outside existing developed areas shall be permitted only where 50 percent of the usable parcels in the area have been developed and the created parcels would be no smaller than the average size of surrounding parcels.

(b) Where feasible, new hazardous industrial development shall be located away from existing developed areas.

(c) Visitor-serving facilities that cannot feasibly be located in existing developed areas shall be located in existing isolated developments or at selected points of attraction for visitors.

DCPP Response:
Section 30250 of the Coastal Act is not applicable to consistency review of license renewal because license renewal is a continuation of existing development, not new development.

<u>Section 30251 – Scenic and visual qualities</u>

Requirements:
The scenic and visual qualities of coastal areas shall be considered and protected as a resource of public importance. Permitted development shall be sited and designed to protect views to and along the ocean and scenic coastal areas, to minimize the alteration of natural land forms, to be visually compatible with the character of surrounding areas, and, where feasible, to restore and enhance visual quality in visually degraded areas. New development in highly scenic areas such as those designated in the California Coastline Preservation and Recreation Plan prepared by the Department of Parks and Recreation and by local government shall be subordinate to the character of its setting.

DCPP Response:
There is no new development associated with license renewal. License renewal is consistent with Section 30251 of the Coastal Act requiring consideration and protection of scenic and visual qualities of coastal areas because the additional years of DCPP operations will not affect the scenic and visual qualities of coastal areas as PG&E plan to continue current operations, land use, and land practices.

<u>Section 30252 – Maintenance and enhancement of public areas</u>

Requirements:
The location and amount of new development should maintain and enhance public access to the coast by (1) facilitating the provision or extension of transit service, (2) providing commercial facilities within or adjoining residential development or in other areas that will minimize the use of coastal access roads, (3) providing nonautomobile circulation within the development, (4) providing adequate parking facilities or providing substitute means of serving the development with public transportation, (5) assuring the potential for public transit for high intensity uses such as high-rise office buildings, and by (6) assuring that the recreational needs of new residents will not overload nearby coastal recreation areas by correlating the amount of development with local park acquisition and development plans with the provision of onsite recreational facilities to serve the new development.

DCPP Response:
There is no new development associated with license renewal. License renewal is consistent with Section 30252 of the Coastal Act requiring maintenance and enhancement of public areas supporting coastal access because the additional years of DCPP operations will continue existing coastal access as described in response to Section II, "Public Access."

<u>Section 30253 – Safety, stability, pollution, energy conservation, visitors</u>

Requirements:
New development shall:

1. *Minimize risks to life and property in areas of high geologic, flood, and fire hazard.*
2. *Assure stability and structural integrity, and neither create nor contribute significantly to erosion, geologic instability, or destruction of the site or surrounding area or in any way require the construction of protective devices that would substantially alter natural landforms along bluffs and cliffs.*
3. *Be consistent with requirements imposed by an air pollution control district or the State Air Resources Control Board as to each particular development.*
4. *Minimize energy consumption and vehicle miles traveled.*
5. *Where appropriate, protect special communities and neighborhoods which, because of their unique characteristics, are popular visitor destination points for recreational uses.*

DCPP Response:
Section 30253 is not applicable to consistency review of license renewal because there is no new development associated with license renewal. The additional years of DCPP operations will not cause: (1) erosion, geological instability or destruction of the site or surrounding area, or (2) additional air pollution. Additionally, there are no special communities or neighborhoods near DCPP.

<u>Section 30254 – Public works facilities</u>

Requirements:
New or expanded public works facilities shall be designed and limited to accommodate needs generated by development or uses permitted consistent with the provisions of this division; provided, however, that it is the intent of the Legislature that State Highway Route 1 in rural areas of the coastal zone remain a scenic two-lane road. Special districts shall not be formed or expanded except where assessment for, and provision of, the service would not induce new development inconsistent with this division. Where existing or planned public works facilities can accommodate only a limited amount of new development, services to coastal dependent land use, essential public services and basic industries vital to the economic health of the region, state, or nation, public recreation, commercial recreation, and visitor-serving land uses shall not be precluded by other development.

DCPP Response:
Section 30254 is not applicable to consistency review of license renewal because DCPP is not a public works facility.

<u>Section 30254.5 – Sewage treatment plants and conditions</u>

Requirements:
Notwithstanding any other provision of law, the commission may not impose any term or condition on the development of any sewage treatment plant which is applicable to any future development that the commission finds can be accommodated by that plant consistent with this division. Nothing in this section modifies the provisions and requirements of Sections 30254 and 30412.

DCPP Response:
Section 30254.5 is not applicable to consistency review of license renewal because there is no new development associated with license renewal.

<u>Section 30255 – Priority of coastal-dependent developments</u>

Requirements:
Coastal-dependent developments shall have priority over other developments on or near the shoreline. Except as provided elsewhere in this division, coastal-dependent developments shall not be sited in a wetland. When appropriate, coastal-related developments should be accommodated within reasonable proximity to the coastal-dependent uses they support.

DCPP Response:
Section 30255 is not applicable to consistency review of license renewal because there is no new development associated with license renewal.

VII. **Industrial Development**

<u>Section 30260 – Location or expansion</u>

Requirements:
Coastal-dependent industrial facilities shall be encouraged to locate or expand within existing sites and shall be permitted reasonable long-term growth where consistent with this division. However, where new or expanded coastal-dependent industrial facilities cannot feasibly be accommodated consistent with other policies of this division, they may nonetheless be permitted in accordance with this section and Sections 30261 and 30262 if (1) alternative locations are infeasible or more environmentally damaging; (2) to do otherwise would adversely affect the public welfare; and (3) adverse environmental effects are mitigated to the maximum extent feasible.

DCPP Response:
Section 30260 is not applicable to consistency review of license renewal because there is no new development associated with license renewal.

<u>Section 30261 – Use of tanker facilities; liquefied natural gas terminals</u>

Requirements:
Multicompany use of existing and new tanker facilities shall be encouraged to the maximum extent feasible and legally permissible, except where to do so would result in increased tanker operations and associated onshore development incompatible with the land use and environmental goals for the area. New tanker terminals outside of existing terminal areas shall be situated as to avoid risk to environmentally sensitive areas and shall use a monobuoy system, unless an alternative type of system can be shown to be environmentally preferable for a specific site. Tanker facilities shall be designed to (1) minimize the total volume of oil spilled, (2) minimize the risk of collision from movement of other vessels, (3) have ready access to the most effective feasible containment and recovery equipment for oil spills, and (4) have onshore deballasting facilities to receive any fouled ballast water from tankers where operationally or legally required.

DCPP Response:
Section 30261 is not applicable to consistency review of license renewal because there are no tanker facilities or liquefied natural gas terminals at DCPP.

<u>Section 30262 – Oil and gas development</u>

Requirements:
a) Oil and gas development shall be permitted in accordance with Section 30260, if the following conditions are met:

(1) The development is performed safely and consistent with the geologic conditions of the well site.
(2) New or expanded facilities related to that development are consolidated, to the maximum extent feasible and legally permissible, unless consolidation will have adverse environmental consequences and will not significantly reduce the number of producing wells, support facilities, or sites required to produce the reservoir economically and with minimal environmental impacts.
(3) Environmentally safe and feasible subsea completions are used when drilling platforms or islands would substantially degrade coastal visual qualities unless use of those structures will result in substantially less environmental risks.
(4) Platforms or islands will not be sited where a substantial hazard to vessel traffic might result from the facility or related operations, determined in consultation with the United States Coast Guard and the Army Corps of Engineers.

(5) The development will not cause or contribute to subsidence hazards unless it is determined that adequate measures will be undertaken to prevent damage from such subsidence.
(6) With respect to new facilities, all oilfield brines are reinjected into oil-producing zones unless the Division of Oil and Gas of the Department of Conservation determines to do so would adversely affect production of the reservoirs and unless injection into other subsurface zones will reduce environmental risks. Exceptions to reinjections will be granted consistent with

the Ocean Waters Discharge Plan of the State Water Resources Control Board and where adequate provision is made for the elimination of petroleum odors and water quality problems.
(7)(A) All oil produced offshore California shall be transported onshore by pipeline only. The pipelines used to transport this oil shall utilize the best achievable technology to ensure maximum protection of public health and safety and of the integrity and productivity of terrestrial and marine ecosystems.

(B) Once oil produced offshore California is onshore, it shall be transported to processing and refining facilities by pipeline.

(C) The following guidelines shall be used when applying subparagraphs (A) and (B):

(i) "Best achievable technology," means the technology that provides the greatest degree of protection taking into consideration both of the following:

(I) Processes that are being developed, or could feasibly be developed, anywhere in the world, given overall reasonable expenditures on research and development.

(II) Processes that are currently in use anywhere in the world. This clause is not intended to create any conflicting or duplicative regulation of pipelines, including those governing the transportation of oil produced from onshore reserves.

(ii) "Oil" refers to crude oil before it is refined into products, including gasoline, bunker fuel, lubricants, and asphalt. Crude oil that is upgraded in quality through residue reduction or other means shall be transported as provided in subparagraphs (A) and (B).

(iii) Subparagraphs (A) and (B) shall apply only to new or expanded oil extraction operations. "New extraction operations" means production of offshore oil from leases that did not exist or had never produced oil, as of January 1, 2003, or from platforms, drilling island, subsea completions, or onshore drilling sites, that did not exist as of January 1, 2003. "Expanded oil extraction" means an increase in the geographic extent of existing leases or units, including lease boundary adjustments, or an increase in the number of well heads, on or after January 1, 2003.

(iv) For new or expanded oil extraction operations subject to clause (iii), if the crude oil is so highly viscous that pipelining is determined to be an infeasible mode of transportation, or where there is no feasible access to a pipeline, shipment of crude oil may be permitted over land by other modes of transportation, including trains or trucks, which meet all applicable rules and regulations, excluding any waterborne mode of transport.

(8) If a state of emergency is declared by the Governor for an emergency that disrupts the transportation of oil by pipeline, oil may be transported by a waterborne vessel, if authorized by permit, in the same manner as required by emergency permits that are issued pursuant to Section 30624.

(9) In addition to all other measures that will maximize the protection of marine habitat and environmental quality, when an offshore well is abandoned, the best achievable technology shall be used.

b) Where appropriate, monitoring programs to record land surface and near-shore ocean floor movements shall be initiated in locations of new large-scale fluid extraction on land or near shore before operations begin and shall continue until surface conditions have stabilized. Costs of monitoring and mitigation programs shall be borne by liquid and gas extraction operators.
c) Nothing in this section shall affect the activities of any state agency that is responsible for regulating the extraction, production, or transport of oil and gas.

DCPP Response:
Section 30262 is not applicable to consistency review of license renewal because DCPP does not develop oil or gas resources, and none are known to be present on the lands or accessible from the lands, comprising the plant site and owner controlled area.

<u>Section 30263 – Refineries or petrochemical facilities</u>

Requirements:
(a) New or expanded refineries or petrochemical facilities not otherwise consistent with the provisions of this division shall be permitted if (1) alternative locations are not feasible or are more environmentally damaging; (2) adverse environmental effects are mitigated to the maximum extent feasible; (3) it is found that not permitting such development would adversely affect the public welfare; (4) the facility is not located in a highly scenic or seismically hazardous area, on any of the Channel Islands, or within or contiguous to environmentally sensitive areas; and (5) the facility is sited so as to provide a sufficient buffer area to minimize adverse impacts on surrounding property.

(b) New or expanded refineries or petrochemical facilities shall minimize the need for once-through cooling by using air cooling to the maximum extent feasible and by using treated waste waters from inplant processes where feasible.

DCPP Response:
Section 30263 is not applicable to consistency review of license renewal because license renewal is a continuation of existing development, not new development.

<u>Section 30264 – Thermal electric generating plants</u>
Requirements:
Notwithstanding any other provision of this division, except subdivisions (b) and (c) of Section 30413, new or expanded thermal electric generating plants may be constructed in the coastal zone if the proposed coastal site has been determined by the State Energy Resources Conservation and Development Commission to have greater relative merit pursuant to the provisions of Section 25516.1 than available alternative sites and related facilities for an applicant's service area which

have been determined to be acceptable pursuant to the provisions of Section 25516.

DCPP Response:
Section 30264 is not applicable to consistency review of license renewal because license renewal is a continuation of existing development, not new development.

<u>Section 30265 – Legislative findings and declarations; offshore oil transport and refining</u>

Requirements:
The Legislature finds and declares all of the following:
(a) Transportation studies have concluded that pipeline transport of oil is generally both economically feasible and environmentally preferable to other forms of crude oil transport.

(b) Oil companies have proposed to build a pipeline to transport offshore crude oil from central California to southern California refineries, and to transport offshore oil to out-of-state refiners.

(c) California refineries would need to be retrofitted if California offshore crude oil were to be used directly as a major feedstock. Refinery modifications may delay achievement of air quality goals in the southern California air basin and other regions of the state.

(d) The County of Santa Barbara has issued an Oil Transportation Plan which assesses the environmental and economic differences among various methods for transporting crude oil from offshore California to refineries.

(e) The Governor should help coordinate decisions concerning the transport and refining of offshore oil in a manner that considers state and local studies undertaken to date, that fully addresses the concerns of all affected regions, and that promotes the greatest benefits to the people of the state.

DCPP Response:
Section 30265 is not applicable to consistency review of license renewal because there is no offshore oil transport or refining at DCPP.

<u>Section 30265.5 – Governor or designee; coordination of activities concerning offshore oil transport and refining; duties</u>

Requirements:
(a) The Governor, or the Governor's designee, shall coordinate activities concerning the transport and refining of offshore oil. Coordination efforts shall consider public health risks, the ability to achieve short- and long-term air emission reduction goals, the potential for reducing California's vulnerability and dependence on oil imports, economic development and jobs, and other factors deemed important by the Governor, or the Governor's designees.

(b) The Governor, or the Governor's designee, shall work with state and local agencies, and the public, to facilitate the transport and refining of offshore oil in a manner which will promote the greatest public health and environmental and economic benefits to the people of the State.

(c) The Governor, or the Governor's designee, shall consult with any individual or organization having knowledge in this area, including, but not limited to, representatives from the following:

(1) State Energy Resources Conservation and Development Commission

(2) State Air Resources Board
(3) California Coastal Commission
(4) Department of Fish and Game
(5) State Lands Commission
(6) Public Utilities Commission
(7) Santa Barbara County
(8) Santa Barbara County Air Pollution Control District
(9) Southern California Association of Governments
(10) South Coast Air Quality Management Districts

(11) Oil industry
(12) Public interest groups
(13) United States Department of the Interior

(14) United States Department of Energy
(15) United States Environmental Protection Agency

(16) National Oceanic and Atmospheric Administration
(17) United States Coast Guard

(d) This act is not intended, and shall not be construed, to decrease, duplicate, or supersede the jurisdiction, authority, or responsibilities of any local government, or any state agency or commission, to discharge its responsibilities concerning the transportation and refining of oil.

DCPP Response:
Section 30265.5 is not applicable to consistency review of license renewal because there is no offshore oil transport or refining at DCPP.

ATTACHMENT F – SEVERE ACCIDENT MITIGATION ALTERNATIVES

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Acronyms Used in Attachment F

ADV	atmospheric dump valve
AFW	auxiliary feedwater
AOT	allowable outage time
AMSAC	anticipated transient without scram mitigating system actuation circuitry
ARAC	atmospheric release advisory capability
ASME	American Society of Mechanical Engineers
ASW	auxiliary saltwater
ATWS	anticipated transient without scram
ATWT	anticipated transient without trip
B/F	bleed and feed
BNL	Brookhaven National Laboratory
BOP	balance of plant
BWR	boiling water reactor
CCP	centrifugal charging pump
CCW	component cooling water
CDF	core damage frequency
CF	containment failure
CIMIS	California Irrigation Management Information System
CRD	control rod drive
CS	containment spray
CSR	cable spreading room
CST	condensate storage tank
CT	completion time
CTE	completion time extension
DCPP	Diablo Canyon Power Plant
DFO	diesel fuel oil
DOE	Department of Energy
ECCS	emergency core cooling system
EDG	emergency diesel generator
EPRI	Electric Power Research Institute
EPZ	emergency planning zone
ESAM	estimated (equivalent) seismic action multiplier
F&O	fact and observation
FWST	fire water storage tank
GE	general emergency
HEP	human error probability
HPME	high pressure melt ejection
HRA	human reliability analysis
HVAC	heating ventilation and air-conditioning
IA	instrument air
IE	initiating event
IPE	individual plant examination
IPEEE	individual plant examination – external events

Acronyms Used in Attachment F

ISGTR	induced steam generator tube rupture
ISLOCA	interfacing system LOCA
LAR	license amendment request
LCV	level control valve
LERF	large early release frequency
LLOCA	large loss of coolant accident
LOCA	loss of coolant accident
LODI	Lagrangian operational dispersion integrator
LOOP	loss of off-site power
LTSP	long-term seismic program
MAAP	modular accident analysis program
MACCS2	MELCOR accident consequences code system, version 2
MACR	maximum averted cost-risk
MCR	main control room
MDP	motor-driven auxiliary feedwater pump
MFW	main feedwater
MLOCA	medium loss of coolant accident
MMACR	modified maximum averted cost-risk
MOV	motor operated valve
MSIV	main steam isolation valve
MSPI	mitigating systems performance index
N2	nitrogen
NCP	normal charging pump
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NRC	U.S. Nuclear Regulatory Commission
OECR	off-site economic cost risk
PACR	potential averted cost-risk
PDP	positive displacement pump
PG&E	Pacific Gas & Electric
PORV	power operated relief valve
PRA	probabilistic risk analysis
PSA	probabilistic safety assessment
PTS	pressurized thermal shock
PWR	pressurized water reactor
RCP	reactor coolant pump
RCS	reactor coolant system
RDR	real discount rate
RHR	residual heat removal
RI-ISI	risk-informed in-service inspection
RITSTF	risk-informed technical specification test frequency
RM	risk management
RPV	reactor pressure vessel
RRW	risk reduction worth

Acronyms Used in Attachment F

RWR	raw water reservoir
RWST	refueling water storage tank
SAMA	severe accident mitigation alternative
SBO	station blackout
SSC	system, structure, component
SEIS	seismic
SER	safety evaluation report
SF	split fraction
SG	steam generator
SGTR	steam generator tube rupture
SI	safety injection
SLB	steam line break
SLOCA	small loss of coolant accident
SR	supporting requirement
SRV	safety relief valve
SSPS	solid state protection system
SWGR	switchgear
TD	turbine-driven
UPS	uninterruptible power supply
VCT	volume control tank
VSLOCA	very small loss of coolant accident
WOG	Westinghouse Owner’s Group

SEVERE ACCIDENT MITIGATION ALTERNATIVES

The severe accident mitigation alternatives (SAMA) analysis discussed in Section 4.20 is presented below.

F.1 METHODOLOGY

The methodology selected for this analysis is contained in NEI 05-01, Severe Accident Mitigation Alternatives (SAMA) Analysis Guidance Document (Reference 13), which has been reviewed and endorsed by the NRC. It involves identifying SAMA candidates that have potential for reducing plant risk and determining whether or not the implementation of those candidates is beneficial on a cost-risk reduction basis. The metrics chosen to represent plant risk include the core damage frequency (CDF), the dose-risk, and the offsite economic cost-risk. These values provide a measure of both the likelihood and consequences of a core damage event.

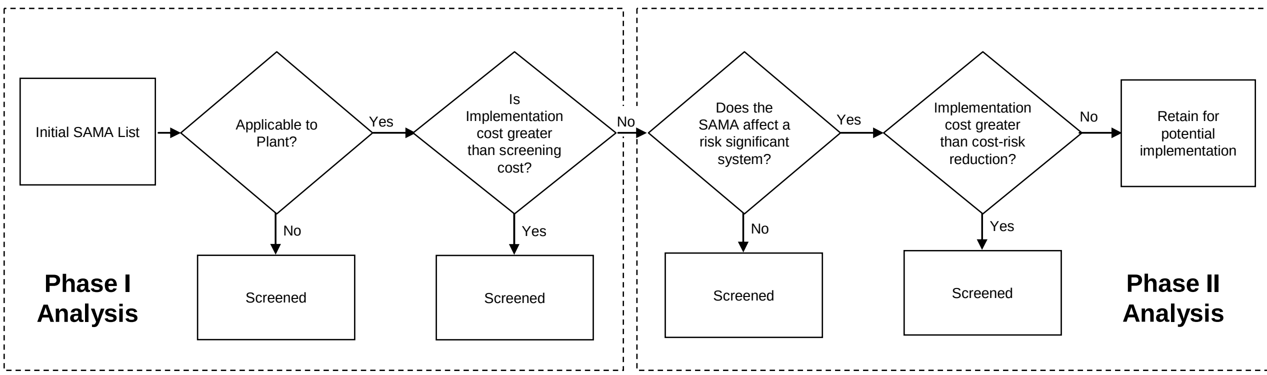
The SAMA process consists of the following steps:

- Diablo Canyon Power Plant (DCPP) Probabilistic Risk Assessment (PRA) Model – Use the DCPP Internal Events PRA model as the basis for the analysis (Section F.2). Incorporate External Events contributions as described in Section F.4.6.2.
- Level 3 PRA Analysis – Use DCPP Level 1 and 2 Internal Events PRA output and site-specific meteorology, demographic, land use, and emergency response data as input in performing a Level 3 PRA using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section F.3). Incorporate External Events contributions as described in Section F.4.6.2.
- Baseline Risk Monetization – Use U.S. Nuclear Regulatory Commission (NRC) regulatory analysis techniques to calculate the monetary value of the unmitigated DCPP severe accident risk. This becomes the maximum averted cost-risk that is possible (Section F.4).
- Phase 1 SAMA Analysis – Identify potential SAMA candidates based on the DCPP Probabilistic Risk Assessment (PRA), Individual Plant Examination – External Events (IPEEE), and documentation from the industry and the NRC. Screen out SAMA candidates that are not applicable to the DCPP design or are of low benefit in pressurized (PWRs) such as DCPP, candidates that have already been implemented at DCPP or whose benefits have been achieved at DCPP using other means, and candidates whose estimated cost exceeds the maximum possible averted cost-risk (Section F.5).

- Phase 2 SAMA Analysis – Calculate the risk reduction attributable to each of the remaining SAMA candidates and compare to the estimated cost of implementation to identify the net cost-benefit. PRA insights are also used to screen SAMA candidates in this phase (Section F.6).
- Uncertainty Analysis – Evaluate how changes in the SAMA analysis assumptions might affect the cost-benefit evaluation (Section F.7).
- Conclusions – Summarize results and identify conclusions (Section F.8).

The steps outlined above are described in more detail in the subsections of this appendix. The graphic below summarizes the high level steps of the SAMA process.

SAMA SCREENING PROCESS



F.2 DIABLO CANYON PRA MODEL

The SAMA analysis is based upon the 2009 interim DCPP PRA model for internal events (i.e., DC01A model). The original PRA model was submitted in 1988 as part of the Long-Term Seismic Program (LTSP) (Reference 30) and has been subsequently updated a number of times to maintain design fidelity with the operating plant and reflect the latest PRA technology.

The following subsections provide more detailed information related to the evolution of the Diablo Canyon Internal Events PRA model and the current results. These topics include:

- PRA changes since the IPE / IPEEE
- Level 1 model overview
- Level 2 model overview
- PRA model review summary

Sections F.4.6.2 and F.5.1.7 provide a description of the process used to integrate external events contribution into the Diablo Canyon SAMA process.

F.2.1 PRA MODEL BACKGROUND

The DCPRA-1988 model was a full-scope Level 1 PRA that evaluated internal and external events (Reference 29). The NRC reviewed the LTSP and issued Supplement No. 34 to NUREG-0675 (Reference 31) in June 1991, accepting the DCPRA-1988. Brookhaven National Laboratory (BNL) performed the primary review of the DCPRA-1988 for the NRC; their review is documented in NUREG/CR-5726 (Reference 38).

The original design of the NSSS and BOP systems of Unit 2 is identical to that of Unit 1. The consistency in design and operation of both units has been maintained. The difference between the two units in terms of their design, operation, equipment reliability and availability, was minor and did not warrant development of a separate PRA model for each unit. As such, the results and insights of the Unit 1 PRA model should be directly applicable to Unit 2 for most applications.

The DCPRA-1988 was subsequently updated to support the Individual Plant Examination (IPE) in 1991 and the Individual Plant Examination for External Events (IPEEE) in 1993. Since 1993, several other updates have been made to incorporate plant and procedure changes, update plant-specific reliability and unavailability data, improve the fidelity of the model, incorporate Westinghouse Owners Group (WOG) Peer Review comments (Reference 44), and support other applications, such as On-line Maintenance, Risk-Informed In-Service Inspection (RI-ISI), Emergency Diesel Generator Completion Time Extension (EDG CTE) and Mitigating System Performance Index (MSPI).

The DCPRA model updates and the quantification of the model since the original DCPRA-1988 are described in the various revisions of the Calculation File C.9. The vintage of the PRA model is designated by the year in which the update was last completed. It should be noted that updates and re-quantification of the model may have also been performed in the year(s) prior to the establishment of the model vintage. For example, PRA model designated DCPRA-1996 was completed in 1996 but the update was performed in 1995 and 1996. In more recent updates, the updated PRA models are designated by a revision number. For example, the latest Revision 1A of the DCPRA model has been designated DC01A.

The subsections below describe the DCPRA model development from the original DCPRA-1988 model to the current DCPRA model (DC01A), and the revision of the Calculation File C.9 that describes the updates performed for in the PRA model.

F.2.1.1 MODEL DCPRA-1988 (LONG TERM SEISMIC PROGRAM)

The objective of the “Long Term Seismic Program” was to satisfy the conditions for issuing the full-power operating license for Unit 1 and 2 by the USNRC. One of the conditions involves the development of and evaluation using a Probabilistic Risk Analysis. The LTSP plan was developed and submitted to the USNRC in early 1985 and was approved by the USNRC in July 1985. The LTSP evaluation was completed in 1988 and a final report (Reference 30) was submitted to the USNRC for review in July 1988.

The review of the LTSP–PRA was performed by the USNRC staff and with the assistance of the Brookhaven National Laboratory (BNL) from 1988 through 1990. BNL was selected by the USNRC to be the technical lead for the review. The USNRC issued Supplement No. 34 to the Safety Evaluation Report NUREG-0675 (SSER 34) in June 1991 (Reference 31), concluding that PG&E has met the probabilistic risk analysis part of the license condition.

A summary of the PRA results is shown in the table below:

Contributor	Mean Core Damage Frequency (per year)
Seismic Events	3.7E-05
Internal Events	1.3E-04
Other External Events	3.9E-05
Total	2.0E-04

The five internal initiating events that have substantial contribution to the Internal Events CDF were:

- Loss of Offsite Power (32.5 percent)
- Reactor Trip (12.5 percent)
- Turbine Trip (11.2 percent)
- Partial Loss of Main Feedwater (8.4 percent)
- Loss of 1 DC Bus (7.3 percent)

The remaining 28 percent is distributed among many other events.

The contributions to the “Other External Events” category came primarily from the fire and flood scenarios.

F.2.1.2 MODEL DCPRA-1991 (INDIVIDUAL PLANT EXAMINATION - IPE)

The Diablo Canyon IPE was submitted to the NRC by a letter dated April 14, 1992 in response to Generic Letter 88-20, “Individual Plant Examination for Severe Accident Vulnerabilities – 10CFR 50.54(f).” The NRC issued its staff evaluation of the Diablo Canyon IPE and accepted the study by letter dated June 30, 1993 (Reference 36).

To fulfill the requirements of the IPE, the original PRA model DCPRA_1988 was updated to:

- Reflect the current plant design and operation, which included the use of updated design information through June 1990, and operational data through December 1989.
- Incorporate comments from the lead consultant for the DCPRA-1988 model, and NRC/BNL comments on the model into the updated PRA model
- Expand the DCPRA-1988 model to include the Level 2 containment performance analysis

The following summarized the plant modifications / improvements incorporated into the PRA model:

1. Diesel Generator Fuel-oil Transfer System. Recirculation lines were added to the system to allow the system to operate continuously once started. This eliminates multiple start demands of the system and hence increasing the reliability of the system.

   In addition, manual operation of the system level control valves on the diesel generator day tanks was provided and to allow a portable engine-driven pump to be connected to the system.
2. Charging Pump Backup Cooling. Provisions were made to allow the use of fire water to cool one of the centrifugal charging pumps in the event of a total loss of component cooling water. This allows reactor coolant pump seal injection and therefore maintains RCP seal cooling in the event of a complete loss of component cooling water.

The core damage frequency from the IPE is 8.8E-05 per year. The CDF is lower than that of the original DCPRA-1988 model due to the implementation of the above improvements and the incorporation of the improvements into PRA model. The dominant initiating event category contributors to this CDF are given below:

- Loss of Offsite Power (41 percent)
- General Transients (Reactor Trip, Turbine Trip, etc.) (26 percent)
- LOCAs (Excessive, Large, Medium or Small) (9.3 percent)
- Loss of One DC Bus (F, G or H) (8.2 percent)
- Loss of ASW or CCW (6.2 percent)
- Floods (3.6 percent)

The Level 2 results were provided in Release Category Groups and the annual contributions from these groups are presented in the table below:

Release Category Group	Frequency (per year)	Percentage
Small, Early Containment Failure	7.61E-06	8.7
Large, Early Containment Failure	2.45E-06	2.9
Late Containment Failure	3.97E-05	45.2
Containment Bypass	1.62E-06	1.8
Long Term Containment Intact	3.64E-05	41.4

The large early containment failure release group is dominated by those HPME direct containment heating sequences (58 percent) that are predicted to occur at vessel breach and are predicted to cause large containment failures. The second most likely cause of early containment failure is hydrogen burns (26 percent).

F.2.1.3 MODEL DCPRA-1993 (INDIVIDUAL PLANT EXAMINATION FOR EXTERNAL EVENTS - IPEEE)

The Diablo Canyon IPEEE report was submitted to the NRC by a letter dated June, 1994 in response to Generic Letter 88-20, Supplement 4 (Reference 32) which requested each utility to perform an Individual Plant Examination of External Events for severe accident vulnerabilities. The results of the IPEEE showed that no vulnerabilities to severe accidents at the plant due to external events were identified. In addition, no containment performance vulnerabilities were identified in this study. The Diablo Canyon IPEEE was accepted by the NRC via a letter dated December 4, 1997 (Reference 40).

To fulfill the requirements of the NRC GL 88-20, Supplement 4, the original PRA model DCPRA_1988 was updated to:

- Reflect the current plant design and operation, which included the use of updated design information through March 1993, operational data through December 1991, and human action failure rates and internal events updated through June, 1993.
- Perform a containment performance assessment for the seismic, fire and “other” external events PRA

The following summarized the plant modifications / improvements incorporated into the PRA model:

1. Dedicated Sixth Emergency Diesel Generator. This plant modification has a significant impact on the plant safety as it increases the availability of the backup power for the Vital AC Bus F. This has reduced the contribution of loss of offsite power events to the overall core damage frequency.
2. Revision of the 230 kV Switchyard Fragility. After the Loma Prieta earthquake, the NRC requested that PG&E reevaluate the fragility of the 230 kV switchyard based on the Loma Prieta earthquake experience. This reevaluation resulted in the change in the fragility of the switchyard which was used in the IPEEE.

The results of the IPEEE indicate that the core damage frequency due to seismic events is 4.0E-05 per year and that due to fire events is 2.7E-05 per year. It was determined that each of the “other” external events evaluated contributed less than 1.0E-06 per year to core damage and were screened out as a result. These results do not differ significantly from those previously determined from the LTSP evaluation.

The most important seismic sequences were the seismic-induced station blackout with the following characteristics:

- Seismic event that fails 500 kV and 230 kV power as well as a primary turbine building shear wall, causing the loss of all vital AC power.
- Seismic event that fails 500 kV and 230 kV power with the random failure of all diesel generators.

The fire risks were dominated by fires in the control room and the cable spreading rooms.

The external events impact on containment performance was also assessed which included the evaluation of the containment structure, penetrations, hatches, isolation valves and the containment heat removal capability. These SSCs have high seismic capabilities. Containment performance for fire initiators was conservatively evaluated and it was determined that sequences are similar to those of the internal events. The conclusion was that external events do not pose any unique threat to containment performance, and it is not significantly different than that identified in the IPE.

F.2.1.4 MODEL DCPRA-1995

The update and revision of the DCPRA-1995 model was completed in May 1996. The important changes to the model are documented in Revision 5 of Calculation File C.9 and they are summarized below:

- Addition of the two backup battery chargers 121 and 131 in the model to reduce unnecessary conservatism.
- AFW pump surveillance frequencies were changed from monthly to quarterly.
- An alignment was added to the DFO system (top event FO) to model unavailability during STP P-12B (1 and 2).
- The initial power alignments (i.e., Normal vs. Backup) were switched for the DFO pumps modeled in top event FO.
- The testing frequency for valves 8821A/B in the SI system model (top event SI) was changed from refueling to quarterly.
- The entire instrument AC system model (top events I1, I2, I3, and I4) was modified to reflect the replacement of the old instrument inverters with new uninterruptible power supplies (UPS units).
- The probability distributions of RCP seal leakage leading to core uncovery as a function of time, used in the electric power recovery model (top event RE) were replaced with new distributions which are based on calculations performed for the qualified O-ring material.

  Additionally, the electric power recovery model was revised to always select the distributions for core uncovery time (from RCP seal LOCAs) for scenarios with no depressurization / cooldown.
- The SSPS system model was modified to incorporate (1) the Eagle 21 modification which included the deletion of the High Steam Differential Pressure, High Steam Flow, and the Low-Low Tavg input signals; and (2) the design modifications and testing frequency changes made to reduce the CVCS letdown and charging valves testing frequency.
- The ASW system model was modified to (1) create a new split fraction, ASG, for LOSP and all support available, (2) remove demusseling from a number of alignments, (3) use the unavailability variable ZMVU2F/D for the unit-to-unit crosstie valve (this also effected Top Event AI), and (4) reflect the train separation of the ASC split fraction. A review of the quantification indicated that split fractions AS4 and AS7 were not being properly selected, so the event tree split fraction rules were modified accordingly.

The operational data from 01/ 01/92 through 12/31/94 were used in the update of the initiating event frequency, component failure rate, equipment maintenance unavailability and common cause failure probability. The common cause failure probabilities were calculated based on the updated component failure rates. No updates were done on the alpha factors for common cause failure probability.

The core damage frequency in the updated DCPRA-1995 model for internal events (including flooding events) is 4.52E-05 per year. The important initiating event contributors and their percentage contributions to the total internal events CDF are shown below:

- Loss of Offsite Power (18.4 percent)
- Loss of Auxiliary Saltwater (12.0 percent)
- Medium LOCA (10.0 percent)
- Reactor Trip (8.1 percent)
- Turbine Trip (6.8 percent)
- Flooding Scenario FL1 (5.5 percent)
- Large LOCA (4.6 percent)
- Loss of DC Bus (G) (4.3 percent)
- Partial Loss of MFW (4.0 percent)
- Loss of DC Bus (F) (3.4 percent)

The decrease in the internal events CDF when compared to that for the IPE is attributable to the changes in the PRA model described above.

F.2.1.5 MODEL DCPRA-1997

The update and revision of the DCPRA-1997 model was completed in January 1999. The major changes to the model are documented in Revision 6 of Calculation File C.9 and they are summarized below:

- The fail on demand for the DC batteries was removed from the vital DC top events since this failure mode was not considered applicable. Instead, a longer mission time (interval between tests) was assumed for the batteries.
- The surveillance test frequency for SSPS slave relays (part of top events SA and SB) was reduced due to a change in the technical specification.
- Similar electric power recovery factors were added to transient-induced loss of offsite power, as is applied to loss of offsite power initiating events.

- The recovery rules applied when the dedicated fuel oil transfer pumps fail (top event FO fails) were revised to allow recovery of some sequences that are recoverable.
- The ASW success criterion (for top event AS and initiating event LOSW) was modified. For unit to unit ASW crosstie to be available, FCV-601 and both pumps from the opposite unit must be available, consistent with the loss of ASW abnormal operating procedure.
- For the AFW system model, the raw water reservoir was added as a backup source of water to the condensate storage tank (CST).
- The PTS analysis was modified so it assumed reactor vessel conditions as of 2005 instead of end of life (i.e., 2020). Using end of life vessel conditions was overly conservative.

The operational data from 01/01/95 through 11/30/96 were used in the update of the initiating event frequency, and operational data from 01/01/95 through 09/30/96 were used to update component failure rate, equipment maintenance unavailability and common cause failure probability. The common cause failure probabilities were calculated based on the updated component failure rates.

The core damage frequency in the updated DCPRA-1997 model for internal events (including flooding events) is 3.32E-05 per year. The important initiating event contributors and their percentage contributions to the total internal events CDF are shown below:

- Loss of Offsite Power (18.1 percent)
- Medium LOCA (12.0 percent)
- Loss of DC Bus (G) (9.4 percent)
- Loss of DC Bus (F) (9.2 percent)
- Low Auxiliary Saltwater (8.1 percent)
- Flooding Scenario FL1 (7.1 percent)
- Large LOCA (6.1 percent)
- Reactor Trip (3.6 percent)
- Turbine Trip (3.3 percent)

The changes made to DCPRA-1997 model has the effect of lowering the contributions from initiating events Loss of Auxiliary Seawater and general transients such as Reactor Trip and Turbine Trip. However, some conservatism in the modeling regarding the impact on the ASW system initiated by the Loss of DC Bus F or G has caused these initiating events to increase in importance with respect to CDF contribution. This conservative modeling was removed in the next PRA model revision.

F.2.1.6 MODEL DC00

The update and revision of the DC00 model was completed in June 2000. This update was done to support the DCPP Risk-Informed In-service Inspection (RI-ISI) submittal to the NRC. The update and revision was done in two stages: (1) the incorporation of updated component database, system and event tree model changes into the PRA model, and (2) the integration of internal events model, seismic events model, and the fire events model into a single combined PRA model. The major changes to the PRA model are documented in Revisions 7 and 8 of Calculation File C.9, and they are summarized below:

- Auxiliary Salt Water System. Success criteria were changed to be consistent with thermal-hydraulic basis from the “Station Blackout Submittal” (Reference 34) and generic letters on Service Cooling Water Systems. Demusseling valves and associated flow paths were included in the system model (Top Events AS and AI), and system alignment changes were also made to be consistent with current operational practice.
- RCS Pressure Relief System. Added the third PORV (474) in Top Event PR and included a new Top Event (PRX) in the Electric Power Support System Event Tree ELECPWR for questioning RCS pressure relief for a specified set of initiators.
- Event Trees - Changes were made to the General Transient and Support Systems Event Trees stemming from changes to RCS pressure relief (Top Event PR and new Top Event PRX) and Auxiliary Seawater System (Top Event AS), and the related dependencies.
- Balance of Plant (BOP) Systems. Defined a new event tree model BOPSUPP that questions the availability of BOP Systems such as Feedwater, Condensate, Circulating Water / Service Water, Non-Vital Power and Instrument Air.
- Large Early Release Frequency (LERF). Quantification of LERF was included in the model so that it can be easily juxtaposed with the commonly used figure of merit, Core damage Frequency (CDF).

The first revision of Alpha factors for the calculation of common cause failure probability was performed for this update. New common cause groups were defined for the following components:

- RHR MOVs (Reference 57)
- DC Battery Chargers (Reference 41)
- DC Batteries (Reference 41)

Alpha factors were updated for the following components based on the more recent common cause failure databases:

- Diesel Generators (Reference 57)
- Residual Heat Removal Pumps (Reference 57)
- Auxiliary Feedwater Pumps (Reference 57)
- Auxiliary Saltwater Pumps (Reference 57)
- Reactor Trip Breakers (Reference 39)
- RT Breaker UV Coils (Reference 39)
- RT Breaker Shunt Trip Coils (Reference 39)

The alpha factors used in the PRA were updated with DCPP plant specific data from November 1984 through September 1996.

Several new initiating events were added:

- Intake Internal Flooding – FLLOSW
- Load Rejection – LREJU
- Loss of Instrument Air – LOIA
- Feedwater Line Break Outside Containment – FWLBO
- Loss of Non-Vital Electric Bus – LNVEL
- Loss of Turbine Building Service Cooling Water – LSCW
- Catastrophic RCP Seal Failure – SELOCA

The MSRV Stuck Open initiator one was deleted as a result of a review of the NRC Initiating Event Database (NUREG/CR-5750) (Reference 42). New generic priors were generated based on NUREG/CR-5750 and used in this revision, which included an update of DCPP data from 12/31/96 through 11/30/99.

The contributions to the total core damage frequency and large early release frequency from Internal Events, Seismic Events and Fire Events are shown in the table below:

Contributor	Mean Core Damage Frequency (per year)	Mean Large Early Release Frequency (per year)
Internal Events	1.41E-05	5.54E-07
Seismic Events	3.36E-05	1.25E-06
Fire Events	1.50E-05	6.42E-09
Total	6.26E-05	1.81E-06

The important internal initiating event contributors (including flooding events) and their percentage contributions to the total internal events CDF are shown below:

- Flooding Scenario Failing CCW - FL1 (16.6 percent)
- Loss of Offsite Power (16.3 percent)
- Loss of Auxiliary Saltwater (12.3 percent)
- Steam Line Break Inside Containment (10.8 percent)
- Loss of Component Cooling Water (4.5 percent)
- Loss of Switchgear Room Ventilation (3.8 percent)
- Reactor Trip (3.3 percent)
- Catastrophic RCP Seal Failure (3.0 percent)

The CDF contribution from Internal Events from the DC00 PRA model is lower than the previous version of the PRA model. This is due primarily to the changes in the system and event tree models and revised database as indicated above. The contributions to CDF from LOCAs, in particular the Medium and Large LOCA were reduced due primarily to the new initiating event frequencies from NUREG/CR-5750 (Reference 42). Revision in the modeling of impact on the ASW system for loss of DC Bus F and G initiating events had also reduced the contributions of these initiating events to total internal event CDF.

There is no change in the modeling of the seismic initiating events. The seismic-induced CDF is also slightly lower than that from the IPEEE and is due primarily to the updated system models and the revised database used in the PRA.

There is also no change in the modeling of the fire initiating events, Similarly, the fire-induced CDF is also slightly lower than that from the IPEEE and is due primarily to the updated system models and the revised database used in the PRA.

F.2.1.7 MODEL DCC0

The update and revision of the DCC0 model was completed in March 2001 based on the changes made to the DC00 PRA model since June of 2000 – that is, over a period of several months. The major changes to the PRA model are documented in Revision 9 of Calculation File C.9 and they are summarized below:

- AMSAC System. This system was credited to actuate the AFW system and turbine trip. The system model (Top Events AMA and AMB) developed was incorporated into the Mechanical Support Systems event tree MECHSP. The other event tree models were impacted by the implementation of the AMSAC system: General Transient, SGTR, ATWT, and the Interfacing System LOCA event tree model.
- Backfeeding from the 500 kV switchyard. The operator action for backfeeding from the 500kV was implemented via a new Top Event OGR which was added to the Electric Power support system event tree model ELECPWR. New component failure rates / unavailability for equipment associated with the 230kV and 500kV switchgear were developed and used in the system model for the offsite power source.
- Cross-tying of Vital Buses – that is, one diesel generator feeds loads of two vital buses. This recovery action was incorporated into the Electric Power System event tree model ELECPWR.
- Included the aligning of the Raw Water Reservoir (RWR) to the suction of the AFW pumps in Top Event AW.
- Credit was taken for makeup to the RWST (Top Event MU) given loss of Low Head pump trains. Dependency of operator actions between failure to initiate sump recirculation (Top event RF) and the operator actions to makeup to the RWST was considered and incorporated in the model update.
- Electric Power Recovery: The latest HEPs were used in Top Event RE and the battery lifetime was revised from 12 hours to 7 hours.
- Evaluation of Pre-Initiating Event Human Actions. Several such human actions were evaluated and incorporated in the various system models: failure to restore fuel oil system (top Event FO), failure to restore diesel fuel oil LCV control switch, and failure to restore battery charger operability.
- The following HEPs were either newly created or HEPs that were revised / re-evaluated: ZHECC2, ZHEAS5, ZHEFL1, ZHEFL2, ZHEAS4, ZHEBC1, ZHERE8, ZHERE9, ZHEREA, ZHEREB, ZHESV3, ZHEPR1, ZHEAW2, ZHEAW5, ZHEAW6, ZHEMU2, and ZHEHU3. These updated / newly created HEPs were incorporated into the DCC0 PRA model as described above.

The component databases were not updated in this revision of the PRA model. The seismic analysis was updated to allow the use of the safety injection pumps for a Very Small LOCA (VSLOCA) event after the RCS has been sufficiently depressurized.

The Fire Initiating Event FS5 was revised to correctly model its impact on the ASW system, that is, the fire scenario fails only the two Unit 1 ASW pumps instead of all four ASW pumps.

The DCC0 model was quantified and the results of the quantification are provided below:

Contributor	Mean Core Damage Frequency (per year)	Mean Large Early Release Frequency (per year)
Internal Events	1.04E-05	4.94E-07
Seismic Events	3.12E-05	1.28E-06
Fire Events	1.33E-05	6.31E-09
Total	5.38E-05	1.78E-06

The important internal initiating event contributors (including flooding events) and their percentage contributions to the total internal events CDF are shown below:

- Flooding Scenario Failing CCW - FL1 (22.5 percent)
- Loss of Offsite Power (17.8 percent)
- Loss of Auxiliary Saltwater (17.4 percent)
- Loss of Common Cooling Water (6.1 percent)
- Catastrophic RCP Seal Failure (6.0 percent)
- Reactor Trip (4.2 percent)
- Medium LOCA (3.2 percent)

The majority of the reduction in Internal Events CDF when compared to the CDF value of the previous DC00 model is attributable to the following changes to the model:

- The addition of AMSAC to actuate the AFW system and trip the turbine resulted in a reduction in frequency of all the ATWT sequences. It also provides a redundant AFW pump start signal when SSPS fails.
- The steamline break initiators (SLBI and SLBO) now credit manual SSPS actuation.

- The ability to backfeed from the 500 kV switchyard and crosstie the vital buses in accordance with the EOPs was fully implemented.
- Pre-initiator and post-initiator HEPs were updated.
- Unit 2 outage bus durations were changed to reflect more realistic out of service times.

The majority of the reduction in seismic CDF is attributable to the change to the seismic analysis incorporating use of the safety injection pumps (and depressurization) for a very small LOCA (VSLOCA) event.

The reduction in fire CDF is attributable to a correction made to the impact of Fire Initiator FS5 on the ASW system in the PRA model. The reduction in the contributions to CDF by the fire initiating events can also be attributed to the improvement in the internal events portion of the PRA model as described above.

F.2.1.8 MODEL DC01

The update and revision of the DC01 model was initiated in 2004 and it was completed in June 2006. Plant design changes for the period 1/1/200 through 12/31/2004 (Reference 48) were reviewed and plant procedure revisions (then current as of 2/04/2005) were also reviewed (Reference 50). Any plant design and / or procedure changes that have an impact on the PRA model were incorporated into the model. The component database (failure rates, maintenance unavailability, and certain electric power component unavailability) was updated using plant-specific operation data from 10/01/96 through 09/30/01 (Calculation File H.1.5, revision 6). In addition, the updates and revisions of the PRA model leading to the DC01 were done in support of the following DCPP programs: 14 day Diesel Generator AOT LAR submittal, MSPI and Safety Monitor implementation. Note that many of the changes to the PRA model were done to facilitate the implementation of the above programs and did not have significant impact on the CDF and LERF results. Other model changes had an impact on the results of the PRA model.

The major changes to the PRA model are briefly described in Revision 10 of Calculation File C.9 and they are summarized below:

- Separating the 480V buses from the then existing Vital AC Power top events and model the 480V buses in separate top events.
- Separating the batteries from the then existing 125V DC Power top events and model the batteries under separate top events. The batteries are required to provide 125V DC power on demand whereas the battery chargers would provide long tern DC power supply.

  The above model changes allow more accurate modeling of the DC-AC power system interface and the impact of loss of 480V and/or 4kV buses on safety / accident mitigating equipment modeled in the PRA.

  The impacted support system and frontline system event tree models due to the above modeling changes were revised accordingly.
- In most of the then existing system model fault trees, the basic events defined in these fault trees were for “super-components” which contain more than one component and component failure mode. As required by the MSPI program, major equipment failure modes must be modeled explicitly as basic events. Changes were made to many of the mitigating system models to meet this MSPI requirement. These changes do not have any significant impact on the system unavailability and hence plant risk.
- The loss of offsite power initiating event was revised to conform to the information / model in Draft NUREG/CR (INEEL/EXT-04-02326) (Reference 49). The total loss of offsite power frequency is divided into 5 different types of causes and a separate initiating event frequency is then developed for each type. New generic prior distributions were generated using the NRC Initiating Events Database (Reference 49) as a source. The experience data of this data source covers the period between 1986 and 2003, with the Diablo Canyon specific operating records through 9/31/2005. The “new” loss of offsite power initiating events were then updated with the plant specific data.
- The offsite electric power recovery model was updated to reflect the new loss of offsite power durations corresponding to the new set of loss of offsite power initiating events as briefly described above. The offsite power non-recovery curves corresponding to this new set of initiating events were used in the evaluation of the offsite power non-recovery factors.
- Incorporation of the Rhodes RCP Seal LOCA Model for station blackout scenarios. This was done in conjunction with the updated electric power (offsite and onsite) recovery model.
- Extensive revision to the Auxiliary Feedwater System was done for this version of the PRA model. A summary of the system model changes is provided below:
  - Included the Fire Water Storage Tank (FWST) as a supplemental water supply to the CST. Note that the FWST does have sufficient volume to be considered a full backup source in the PRA model.
  - Added new system top events to handle different sets of boundary conditions and corresponding SGs and AFW Pumps Success Criteria

- The RUNOUT protection function for MDP1-2 was added to the system model, while assuming that the pump runout events would not adversely impact MDP 1-3. Note that in the previous model, it was conservatively assumed the guaranteed failure of the motor-driven AFW pumps due to pump runout in the event of depressurization of one or more SGs due to steam line break downstream the MSIVs.
- Credit was given to the safety valves in the event that the 10 percent ADV were not available.

- Depressurization of the RCS was added to the event sequence model via the new Top Event OR instead of being embedded in Top Event MU which previously also included the modeling of the depressurization of RCS for closed loop RHR cooling.
- New probability for the consequential loss of offsite power (LOOPCN) after a plant trip was developed and used in the Top Event OG model which questions the availability of the offsite grid after a plant trip
- The HRA was updated using the EPRI HRA Calculator (Reference 11). This was completed in November of 2002 and the updated HEPs were used in this revision of the PRA model.
- Update to the Level 2 PRA model to allow a more realistic assessment of the Large Early Release Frequency figure or merit (Reference 51).

The DC01 PRA model was quantified and the results of the quantification are provided below:

Contributor	Mean Core Damage Frequency (per year)	Mean Large Early Release Frequency (per year)
Internal Events	1.08E-05	1.60E-06
Seismic Events	3.77E-05	1.89E-06
Fire Events	1.70E-05	-
Total	6.55E-05	3.49E-06 (1)

Note:
(1) Total LERF does not include contribution from fire initiators

The important internal initiating event contributors (including flooding events) and their percentage contributions to the total internal events CDF are shown below:

- Medium LOCA (12.2 percent)
- Flooding Scenario Failing CCW - FL1 (11.6 percent)
- Steam Generator Tube Rupture (11.2 percent)
- Loss of Offsite Power – Grid Related (7.9 percent)

- Reactor Trip (7.8 percent)
- Turbine Trip (5.8 percent)
- Partial Loss of Feedwater (4.7 percent)
- Loss of Switchgear Ventilation (4.2 percent)

There is an increase in the Internal Events CDF of approximately 4 percent from the last quantification (DCC0). Some changes in the model have the effect of increasing the CDF and others have the opposite effect. The resulting increase in Internal Events CDF and the characteristics of the important initiating event contributors are attributable to the following changes to the model:

- An increase in the HEP value following HRA update (Calculation File G.2, Revision 5) (Reference 46). This is from the increase in the risk importance in the Medium and Large LOCA initiator due to the increase in the HEP value for operation actions to switch to sump recirculation mode of operation.
- Modeling of the requirement to depressurize the RCS to terminate the loss of primary coolant to the secondary side and the initiation of closed loop RHR cooling in the event of an un-isolated steam generator tube rupture event (SGTRN). Due to the limited inventory of the SFP, continuous makeup to the RWST as a recovery action requires that the RCS fluid loss be minimized prior to making up to the primary system via spent fuel pumps.
- Modeling of the requirement to depressurize before crediting continuous makeup to the RWST after loss of sump recirculation mode during SLOCA and transient induced LOCA scenarios
- A higher consequential LOSP probability used in the PRA
- New LOSP initiators were defined for this revision of the PRA model that separate offsite power losses into four categories (Grid, Plant, Switchyard and Severe Weather related). The overall effect of these changes to the initiators and to the electric power recovery factors was a decrease in the contribution of LOSP to CDF.
- Addition of common cause failure of DC buses and batteries into the model as evident from the increased contribution to CDF from general transient initiators such as Reactor trip, Turbine Trip, Partial Loss of Feedwater, etc.
- Longer duration assumed for the Emergency Diesel Generator (EDG) maintenance windows as part of the EDG LAR submittal (Reference 47).

The increase in the internal LERF can be attributed to the following changes:

- Requirement to depressurize the RCS to terminate the loss of primary coolant to the secondary side and the initiation of closed loop RHR cooling in the event of an SGTRN event which, as stated above, has increased SGTRN contribution to CDF. Since all SGTRN events resulting in CDF are directly considered to be LERF contributors, the increase in SGTRN CDF has directly resulted in an increase in LERF

- Replacement of the simplified LERF model with revised detailed Level 2 model

The increase in the seismic LERF can be attributed to the above requirement to depressurize the RCS for SGTRN event which has the effect of causing an increase in the Internal Events LERF. Since seismic LERF was quantified with the same simplified LERF model as before, the percentage increase of seismic LERF was less than the percentage increase of Internal Events LERF.

Fire-induced LERF was not quantified in the DC01 model. The new Level 2 model does not account for the effects of fire on containment response.

F.2.1.9 MODEL DC01A

This is an interim model completed in 2009 that incorporates a model change to reflect the replacement of the PDP charging pumps (CHG Pumps 1-3 and 2-3) with centrifugal pumps. One major difference in design between these new pumps and the centrifugal charging pumps is that they do not require CCW for cooling. The changes were documented in (Reference 61) and include:

1. A new top event (CH3PP) was developed to model a RCP seal injection function via the charging pump 1-3 (2-3).
2. The structure of Event Trees GENTRN and SGENTRN were modified to include the Top Event CH3PP.
3. The split fraction rules for Top Event CH3PP and split fraction SE2 were added in GENTRN and SGENTRN Event Trees.

The top event, CH3PP, represents a potential RCP seal injection flow path using the charging pump 1-3 (2-3) regardless of the status of the CCW system. This pump is normally in service and remains in operation during a transient, except when manually tripped or upon a “transfer to diesel load shed” signal. The flow path includes the suction path from either the VCT or RWST, the charging pump, and the discharge path to the RCP seal.

The reliability block diagram of this top event is similar to that of Top Event SE. It consists of the suction flow paths from RWST or VCT, charging pump flow path, and the RCP seal injection flow path. The charging pump 1-3 (2-3) is normally in service taking suction via the VCT and providing normal charging and RCP seal injection flow. Unless the 4KV bus G power supply is transferred to the emergency diesel 1-2 (2-1), the suction path via the VCT remains as is. Therefore, transfer closure of the VCT discharge MOVs (i.e., 112B and 112C) during the mission time would interrupt the seal injection. Upon a transfer to diesel signal, the charging pump 1-3 (2-3) trips, and if needed for the seal injection, requires a manual start. For a modeling simplification, no credit was given for a manual start of the pump and the pump fail-to-start basic event (CH_PP_13_FS) is set to Success. The support requirements are also similar except they do not require CCW cooling flow to the pump lube oil cooler or a SSPS start signal.

Top Event SE does not include the charging pump 1-3 (2-3). However, the effect of the availability of the RCP seal injection flow path (Top Even CH3PP) via the charging pump 1-3 (2-3) is reflected in the split fraction rules of Top Event SE in the Event Trees GENTRN and SGENTRN.

When the RCP seal injection flow path is available (i.e., CH3PP=S) and there is no transfer to diesel/load shed signal (the vital 4kV BUS G is energized from the startup power, OG=S*SG=F), split fraction SE2 (guaranteed success) is used. It is possible to manually restart the charging pump 1-3 (2-3) after an automatic trip due to a load shed signal. However this sequence is not considered at this point as it involves development of an HEP for a manual start of charging pump 1-3 (2-3). This modeling simplification is conservative and its potential contribution is judged to be minimal.

The overall impact of these changes is that the contribution of the RCP seal LOCA is significantly reduced due to an improvement in the RCP seal injection system.

The DC01A PRA model was quantified and the results of the quantification are provided below:

Contributor	Mean Core Damage Frequency (per year)	Mean Large Early Release Frequency (per year)
Internal Events	8.13E-06	1.59E-06
Seismic Events	3.77E-05	1.89E-06
Fire Events	1.39E-05	-
Total	5.97E-05	3.48E-06 (1)

Note:
(1) Total LERF does not include contribution from fire initiators

The important internal initiating event contributors (including flooding events) and their percentage contributions to the total internal events CDF are shown below:

- Medium LOCA (16.2 percent)
- Non-Isolated SGTR for Level 2 (14.9 percent)
- Loss of Offsite Power – Grid Related (10.5 percent)
- Reactor Trip (8.1 percent)
- Turbine Trip (6.1 percent)
- Loss of Switchgear Ventilation (5.5 percent)
- Partial Loss of Main Feedwater (4.9 percent)
- RCP seal Catastrophic Seal Failure (3.7 percent)
- Loss of Condenser Vacuum (3.3 percent)
- Loss of Offsite Power – Severe Weather (3.1 percent)

Figures F.2-1 and F.2-5 depict internal, seismic and fire contribution to CDF and LERF associated with the DC01A PRA model.

F.2.2 DESCRIPTION OF LEVEL 1 TO LEVEL 2 MAPPING

Each accident sequence from the Level 1 event tree quantification has a unique "signature" due to the particular combination of top event successes and failures. Ideally, each accident sequence that results in core damage should be evaluated explicitly in terms of accident progression and the release of radioactive materials, if any, to the environment. However, since there can be millions of these sequences, it is impractical to perform such analyses for each accident sequence. Therefore, the sequences must be grouped into plant damage state (PDS) bins. Each of these PDS bins collects all of those sequences for which progression of core damage, release of fission products from the fuel, and the potential for mitigating source terms are similar. Detailed analyses are then focused on specific sequences selected to represent each of these bins.

F.2.2.1 DEFINITION OF PLANT DAMAGE STATES

The PDS bins become the entry states (similar to Initiating Events for the Level 1 event trees) to the containment event trees (CETs), and are characterized by the thermodynamic conditions in the reactor coolant system and in the containment at the time of severe core damage, and the availability of both passive and active plant features that can terminate the accident or mitigate the release of radioactive materials into the environment.

The plant damage states must be defined such that within a plant damage state, the sequence-to-sequence variability in the containment response is small in comparison with the uncertainties in the outcome of the CET top events. In this manner, the issue of containment response uncertainty, and the evaluation of split fractions for the CET top events can be limited to the assessment of containment response uncertainty.

Before PDSs are defined, plant conditions, systems, and features that can have a significant impact on the potential course of an accident must be identified. Once these are identified, a table is constructed to display all of the potential combinations of the PDS characteristics that are physically possible, and to assign an identifier to each of these combinations. The table that results from this process is referred to as a PDS matrix. The definition of the PDS matrix is based on the anticipated response of the plant and containment to severe accidents. Requirements of Level 1 and 2 analyses must both be considered when constructing the matrix.

The containment event tree (CET) could, in principle, be quantified separately for each PDS as the values of the CET top event split fractions can be dependent on the PDS being analyzed. In practice, however, PDSs can be grouped (or binned) together to minimize the amount of CET quantification. Generally, PDSs of lower frequency are grouped with similar PDSs of higher frequency and potentially higher consequences (referred to as "conservative condensation") into key plant damage states (KPDS).

A representative accident sequence is selected for each KPDS. These representative sequences are analyzed in detail with appropriate thermal-hydraulic and fission product codes such as the Modular Accident Analysis Program (MAAP) to characterize the timing of important events (such as the onset of severe core damage and reactor vessel melt-through), as well as the nature of the core damage and fission product release.

All of the plant model information on the operability status of active systems that is important to the timing and magnitude of the release of radioactive materials must be passed into the CET via the definition of the KPDS. This requires that, in addition to representing the systems and functions that are important to keeping the core cooled, the plant model event trees must also address active systems and functions important to containment isolation, containment heat removal, and the removal of radioactivity from the containment atmosphere. The containment spray system is one example of such systems.

The boundary between the Level 1 event trees and the containment event tree was selected for the following reasons:

- all active systems, including the containment engineered safeguards, are included in the Level 1 Event Trees because their dependencies on support systems such as electrical power and component cooling water can be determined more easily in the Level 1 Event Trees,
- The boundary separates the phenomenological model (the CET) from the Level 1 Event Trees that deal only with active systems and operator actions,
- the boundary separates analyses which can be characterized by likelihood (as measured by frequency, i.e. Level 1 Event Trees) with analyses characterized by uncertainty (as measured by probability, i.e. CET).

Separation of the Level 1 Event Trees and the Containment Event Trees allows flexibility in the modeling process. The Level 1 model can be modified without changing the CET, as long as the PDSs are not changed.

The Containment Event Tree considers the effects of physical and chemical processes on the integrity of the containment and on the release of fission products once core damage has occurred. Considerations that influence progression of core damage, the time and mode of containment failure, and the release of radioactive materials to the environment fall into two categories:

- The physical conditions in the reactor coolant system and containment at the time of vessel melt-through, and
- The status and availability of containment systems.

Physical conditions in the RCS and containment that are defined in the PDS matrix are as follows:

- The pressure inside the reactor vessel at the onset of core damage (the pressure at vessel breach will be assessed in the containment event tree),
- The availability of cooling on the secondary side of the steam generators, and
- Whether or not the reactor cavity is flooded at the time of vessel melt-through.

Thus, the PDS matrix defines the following parameters at the onset of core damage:

- RCS pressure at onset of core damage
- Secondary Side Steam Generator Cooling availability
- Whether the RWST is injected into containment at onset of core damage
- Status of Containment Spray and Containment Heat Removal
- Containment Integrity at time of vessel melt-through

Table F.2-1 presents the five parameters discussed above, the rationale for the category selection, the code used in the PDS matrix, when the code is applicable, binning logic, and any comments. This table fully documents the definition of the plant damage state matrix.

F.2.2.2 ORGANIZATION OF PLANT DAMAGE STATES

To help organize and categorize each unique PDS, Table F.2-2 was developed based on the definitions in Table F.2-1. Each cell in the matrix of Table F.2-2 represents a unique plant damage state. Each PDS is identified by a five character identifier using the codes from Table F.2-1. The five character identifier is named as follows:

- The first character represents RCS pressure at onset of core damage. Valid codes are L, I, H, and S, as described in Table F.2-1.
- The second character represents the availability of secondary side steam generator cooling. Valid codes are N, A, and X as described in Table F.2-1.
- The third character indicates whether water from the RWST had been injected into containment prior to vessel breach. Valid codes are N and Y, as discussed in Table F.2-1.
- The fourth character indicates whether containment spray and containment heat removal are available. Valid codes are A, B, C, D, E, F, G, and N, as discussed in Table F.2-1.
- The fifth character indicates containment isolation and bypass status. Valid codes are I, S, L, B, and V, as discussed in Table F.2-1.

The matrix shown in Table F.2-2 includes 12 rows (representing unique combinations of RCS pressure, status of steam generator cooling, and status of RWST injection into containment) and 32 columns denoting the status of the containment isolation and the availability of containment spray and containment heat removal systems.

The complete PDS matrix shown in Table F.2-2 contains a total of 384 plant damage states. However, the number of PDSs identified in Table F.2-2 can be substantially reduced because some are precluded by DCPP design features, by the type of initiating event, modeling assumptions, or any combination of these reasons. Any PDS that is precluded is shaded and footnoted in Table F.2-2.

F.2.2.3 DISCUSSION OF KEY PLANT DAMAGE STATES

As discussed above, in order to simplify CET quantification, the PDSs are grouped into key plant damage states (KPDS). In general, the following numbered guidelines are used to subsume the PDSs into KPDSs such that the KPDS is bounding from a Level 2 analysis perspective for the PDS grouping. Table F.2-3 presents the sixteen new KPDSs.

1. Higher RCS pressures prior to vessel breach cause greater containment pressure rise and an early challenge to containment integrity. Therefore, a lower pressure PDS could be binned to a higher pressure PDS (indicated by the first letter in the PDS identifier).

2. The unavailability of steam generator cooling increases vessel pressure at breach with the same consequences as discussed in Guideline 1. Therefore, a PDS with steam generator cooling available could be binned to a PDS with steam generator cooling not available. The status of steam generator cooling is indicated by second letter in the PDS identifier.

3. Similar to Guideline 2, a PDS with steam generator cooling not applicable (e.g., large LOCA sequence) could be binned to a PDS with steam generator cooling not available.

4. The failure to inject the contents of the RWST reduces the heat sinks in the containment, eliminates a means of fission product scrubbing, and eliminates a means of cooling the core debris. These factors increase the likelihood of containment failure or increase the source term. A PDS in which the RWST inventory has been injected could be binned to a PDS in which the RWST

inventory has not been injected. The status of the RWST is signified by the third letter in the PDS identifier.

5. In terms of containment heat removal, CFCUs have the greatest capacity and should be effective for the duration of the accident. Recirculation spray is also effective for the duration of the accident, while injection spray is effective for only a few hours. Any PDS that represents greater containment heat removal capacity could be binned to a PDS with less heat removal capacity. The status of containment heat removal is indicated by the fourth letter in the PDS designator.

6. States in which containment integrity is lost will release fission products sooner than states in which containment integrity is maintained. Therefore, a PDS in which containment integrity is maintained could be binned to a PDS without containment integrity. The status of containment integrity is indicated by the fifth letter of the PDS designator.

7. Large containment leaks release fission products more rapidly than small leaks. Therefore, a PDS exhibiting a small leak could be binned to a PDS representing a large leak.

8. Large containment bypasses release fission products more rapidly than small bypasses. Of the accidents analyzed, large containment bypasses have the highest source term and the earliest release of fission products. The large bypass represents the most severe KPDS scenario. Therefore, as a conservative measure, any non-large bypass PDS could be binned to a PDS with a large bypass.

F.2.2.4 DESCRIPTION OF CONTAINMENT EVENT TREE END STATES MAPPED TO RELEASE CATEGORIES

For large, dry containment PWRs such as DCPP, many factors can potentially affect radionuclide releases into the environment following a severe accident. The most important of these factors become the principal issues requiring consideration in the development of release categories. Release categories are groups of containment event tree end states that can be represented by similar source terms; i.e., the variations in source terms for accident sequences within a given release category are smaller than variations from one release category to another. Table F.2-4 shows the principal issues affecting the definition of release categories for large, dry containment PWRs.

F.2.2.4.1 Containment Event Tree Discussion

The containment event tree is shown in Figure F.2-6 with the top events described in Figure F.2-7. All of the quantified sequences which lead to containment failure or containment bypass were binned to the release categories shown in Table F.2-5. The binning logic for the release category assignment is documented in Reference (Reference 35). These release categories address the issues presented in Table F.2-4 and are explained below:

For the containment bypass sequences, separate release categories were created for the interfacing system LOCA and SGTR.

RCS pressure at the time of vessel failure was reduced to three categories, High, Medium, and Low. However, to simplify the RCS pressure category, the medium pressure sequences will be conservatively binned with the high or low pressure sequences as follows:

- For late containment failures where early high retention in the RCS can become a liability, the medium pressure sequences are binned with the high pressure sequences.
- For early-large containment failures, the medium pressure sequences are binned with the low pressure sequences because less retention in the RCS becomes a liability.

- For early-small containment failures, the medium pressure sequences are binned with the high pressure sequences because containment pressures may be greater later in the event and high RCS retention then becomes a liability.

Containment failure time was reduced to either Early (at the time of vessel failure due to DCH and/or hydrogen burning) or Late (> 4 hours after vessel failure due to hydrogen burning and/or long term overpressurization). Additionally, separate categories were created for no containment failure sequences (i.e. long-term intact) and basemat melt-through sequences.

Containment failure size was reduced to either Large (> 3 inch diameter failure where rapid containment depressurization is expected) or Small (< 3 inch diameter failure where gradual containment depressurization is expected).

Containment spray system (in recirculation spray mode) was assumed to be either On or Off for each of the "in-containment" release categories.

Similarly, the core debris was assumed to be either cooled or non-cooled after vessel failure and core relocation for each of the "in-containment" release categories. This assumption is particularly of note to DCPP since a dry cavity is postulated for all non high pressure melt ejection sequences. Note that the CET considers a small, but non-zero probability for non-coolable core slump situations during HPME sequences, which implies that some high pressure sequences will result in CCI. Non-coolable release categories are designated with the letter "U" placed after the name of the similar coolable release category (e.g. RC03 and RC03U).

In summary, Table F.2-5 has a total of 32 release categories (RC01 and RC01U through RC16 and RC16U) that address the "in-containment" release sequences discussed above. Additionally, there are two containment bypass release categories for SGTR and interfacing system LOCA (RC17 and RC18), two containment intact categories for long term containment intact sequences and basemat melt-through sequences (RC20 and RC21), and a category for non-severe core damage sequences with an intact containment (RC19).

F.2.2.4.2 Release Category Source Terms

The source term for a given release category consists of the release fractions for the core radionuclide groups (expressed as fractions of initial core inventory) and the timing of the release. For this analysis, two sets of source terms were generated for each release category. One set was calculated using the parametric computer code ZISOR, which was originally developed to quantify the source terms for the Zion plant. The other set was calculated using MAAP.

ZISOR provides a simple, quick method of generating source terms based on expert opinions of physical phenomena important to fission product transport after core damage. MAAP, on the other hand, explicitly models phenomena important to fission product transport in conjunction with thermal-hydraulic models of the reactor coolant system and containment. PG&E elected to generate both sets of source terms not only to decide which method would be more appropriate to use, but also to gain a better understanding of how plant design, systems availability, and accident scenarios may affect the fission product transport phenomena.

In the following sections, the ZISOR and MAAP methodologies for generating source terms for the DCPRA-1991 are discussed. Additionally, ZISOR and MAAP generated source terms will be discussed and compared and the insights gained from this analysis will be discussed.

F.2.2.4.3 ZISOR Methodology

ZISOR is a parametric computer code originally developed to quantify the source terms for the Zion plant for the NUREG-1150 evaluations (Reference 3). ZISOR attempts to simulate the physical processes important to fission product transport and release, which are explicitly modeled in the more sophisticated codes, by replacing the physical processes with parameters.

Most of the parameters used in the release fraction equations are represented by cumulative probability distributions and are read from an input file by ZISOR. ZISOR is typically run in a "sampling" mode in which most of the factors in the equations are determined by sampling from the distribution given for that parameter. However, for the purposes of the DCPRA-1991 only point value estimations were used. That is, only the central or median value from each distribution was used to represent the various parameters in the release fraction equations.

The parameters used in the release fraction equations which are input as distributions were provided by the Source Term Expert Panel and are fully described in Reference (Reference 28). Note that most distributions provided by the expert panel were for PWR-generic issues. In DCPP specific issues, the Zion distributions were used due to the similarity of the Zion plant to DCPP.

The following parameters relate to the source term issues addressed by the expert panel that provided the parameters as cumulative probability distributions in ZISOR (of which only the central value is used):

FCOR Fraction of each fission product group released from the core to the vessel before or at vessel breach.

FVES Fraction of each fission product group released in the vessel that is subsequently released to the containment before or at vessel breach.

FISG Fraction of each fission product group released from the reactor vessel to the steam generator in an SGTR accident.

FOSG Fraction of each fission product group released from the steam generator to the environment in an SGTR accident.

VDF Decontamination factor for pool scrubbing for an interfacing system LOCA when the break location is underwater at the time of the release.

FCONV Fraction of each fission product group in the containment from an RCS release that is subsequently released from the containment in the absence of mitigating factors such as sprays.

FCCI Fraction of each fission product group in the core material at the start of core-concrete interactions that is released to the containment.

FCONC Fraction of each fission product group in the containment from the CCI release that is released from the containment in the absence of mitigating factors such as sprays.

DFE Decontamination factor for RCS release (i.e. sprays).

DFL Decontamination factor for CCI release (i.e. sprays).

LATEI Fraction of the iodine deposited in the containment which is revolatilized and released to the environment late in the accident.

FLATE Fraction of the amount of each fission product group deposited in the RCS which is revolatilized after vessel breach and released to the containment.

FDCH Fraction of each fission product group in the core material that becomes aerosol particles in a direct containment heating at vessel breach that is released to the environment.

VPSL Decontamination factor for a pool of water overlying the core debris during CCI.

Three other parameters used in the release fraction equations which were not defined as distributions were also used in ZISOR as described below:

FREM Fraction of core material remaining in vessel after vessel breach. This value is internally fixed at 5 percent and was not changed.

FPART Fraction of the core that participates in the CCI.

FPME Fraction of core involved in a high pressure melt ejection.

The ZISOR code determines the amount of radioactive material released to the environment following a severe accident as the sum of an "early" release and a "late" release. The early release (or RCS release), which occurs before, at, or very shortly after the time of vessel failure, is due to fission products that escape from the fuel while the core is still in the RCS. The late release (or CCI release), which occurs several hours after vessel failure, is generally due to fission products that escape from the fuel during CCI. The late release also includes the revolatilized fission products from the RCS release which were deposited on containment and RCS surfaces.

The early (RCS) release is the sum of the fuel releases during the in-vessel phase of the accident and the release resulting from direct containment heating as follows (Note that the index i refers to the nine fission product groups listed in Table F.2-6):

[FCOR(i)*(1-FISG(i))*FVES(i)*FCONV/DFE] + [FCOR(i)*FISG(i)*FOSG(i)] + [(1-FCOR(i))*(1-FREM)*FPME*FDCH(i)*FCONV/DFE]

Where the first term is the early RCS release, the second term is the fraction of the RCS release released from the steam generator in an SGTR, and the third term is the early release due to direct containment heating resulting from a high pressure melt ejection.

The late (CCI) release is the sum of the releases due to CCI and the releases due to late revaporization of the volatile species deposited in the RCS as follows:

[(1-FCOR(i))*(1-FREM)*(1-FPME)*FPART*FCCI(i)*FCONC(i)/DFL]

+ [{FCOR(i)*(1-FISG(i))*(1-FVES(i))+(1-FCOR(i))*FREM}*FLATE(i)*FCONC(i)/DFL]

+ [FCOR(i)*FISG(i)*(1-FOSG(i))*FLATE(i)]

Where the first term is the release from molten core-concrete interactions, the second term is the release due to late revaporizations, and the third term is the release due to late revaporizations of fission products deposited in the steam generator in an SGTR.

To use ZISOR for DCPP, each of the release categories defined in Section F.2.2.4.1 was "re-binned" into the 11-character "bin" which defines the release category to ZISOR. The binning rules for this 11-character bin are given in Table F.2-7. In most cases, the release category binning rules are directly applicable to the ZISOR binning rules for the containment failure mode or spray operation. When the ZISOR bin called for information which was not evident based on the binning rules for the release category, the MAAP results for the most probable key plant damage states contributing to release category were reviewed to determine the most appropriate choice of binning information.

F.2.2.4.4 MAAP Methodology

MAAP Version 3.0B (Reference 9) is a computer code that simulates the response of light water reactor power plants during severe accident sequences. MAAP quantitatively predicts the evolution of a severe accident starting from full power conditions given a set of system faults and initiating events through events such as core melt, reactor vessel failure, and containment failure.

MAAP models thermal hydraulic and fission product behavior in the primary system, steam generators, containment, and auxiliary building. MAAP treats a wide spectrum of phenomena including steam formation, core heatup, cladding oxidation and hydrogen evolution, vessel failure, core-concrete interactions, and fission product release, transport, and deposition.

MAAP was used in simulating the key plant damage states that were discussed in Section F.2.2.3. These simulations provided a best estimate evolution of the accident sequences and do not necessarily lead to containment failure and fission product release. For generating the source terms, only those sequences which lead to containment failure and fission product release need to be simulated. These sequences were grouped into the release categories listed in Table F.2-5 when the CET was quantified.

The KPDS (as the initiating sequence) which contributed the most to each release was determined and MAAP was then used to simulate each release category by initiating an accident with that KPDS. The sequence of events leading to containment failure as determined from the CET was reviewed and those events were manually imposed in the MAAP simulation.

For example, RC03U is a Medium-Low RCS pressure category. However, the most probable KPDSs contributing to this release category were high pressure ones (SXYAI). The binning of a high pressure KPDS into a low pressure release category happens because CET Top Event IP (Induced RCS Hot Leg or Surge Line Failure) fails leading the CET to bin the end state to a low pressure category. To allow MAAP to simulate this release category using the most probable KPDS, a large LOCA was imposed at core uncovery in the SXYAI case to simulate the RCS hot leg failure and the subsequent depressurization before vessel failure. The MAAP simulation then agrees with the release category definition.

It should be noted that in most of the MAAP simulations, the only containment failures occurred due to long term over-pressurization. That is, MAAP predictions of containment pressurization due to hydrogen burning and direct containment heating were never in excess of the median containment failure pressure. The CET on the other hand, has top events which model these phenomena and fail the containment based on the split fractions for that top event. Again, MAAP was forced to agree with the CET release category being modeled by manually imposing a containment failure, either small or large, in the MAAP simulation at the time required to match the release category definition.

F.2.2.4.5 Source Term Results

Source term release fractions and release timings are discussed below. Note that only the release categories with a frequency above the cutoff of 1 x 10-10 /year are reported. Only 29 out of the original 37 release categories have a quantified frequency greater than 1 x 10-10 /year.

E.2.2.4.5.1 Source Term Results

Table F.2-8 presents the source term release fractions for each release category. The table orders the release categories in descending order of frequency for the CET quantification for which recovery actions are not credited so that the most frequently occurring release categories appear first. Note that RC19, the release category in which non-severe core damage sequences were binned, was included for completeness, but no significant releases are postulated for this category since no severe core damage is postulated.

For each release category, the ZISOR calculated source term is reported first and the MAAP calculated source term is reported second. The ZISOR binning information, that is the 11-character "word" which defines the case, and the KPDS which was used in the MAAP calculation are reported in the "ZISOR Bin" column.

For all MAAP calculations, the reported source terms are the release fractions at 50 hours (approximately 2 days) after initiation of the event. It is recognized that in some cases, the release fraction may still be increasing at this point especially in the iodine and cesium species due to revolatilization. However, simulations which were allowed to run for long periods did not show huge increases in the release fractions over the release fraction at 50 hours.

In all cases except the RC20 (long-term containment intact), ZISOR predicts that 100 percent of the noble gases will be released to the environment. MAAP does not always predict this even though MAAP does assume that 100 percent of the noble gases have been released into the containment. Often, this is due to successful actuation of the containment heat removal systems (sprays and CFCUs) which does not allow the containment to pressurize significantly. Thus when the containment failure is imposed, there is little or no driving pressure to force the gases out.

For the volatile iodine (I) and cesium (Cs) fission product species, MAAP will usually under-predict the release fractions by factors of about one to six compared to ZISOR. In general, when the magnitude of the release is considered, volatile releases predicted by MAAP and ZISOR are usually in fair agreement.

For the tellurium (Te) fission product species, MAAP does not predict any release in the debris-coolable cases because MAAP assumes that all the tellurium is chemically bound to the zirconium in the clad and is un-available for in-vessel release. Further, since the debris is cooled, no further oxidation of the zirconium is assumed so that the Te will remain bound with the zirconium in the debris. In debris-non-coolable case, MAAP predicts greater Te releases than ZISOR possibly due to the more accurate CCI simulation in MAAP.

For the semi-volatile strontium (Sr) and barium (Ba) fission product species, MAAP consistently under-predicts the ZISOR predictions for the coolable sequences by factors of 50 and greater. For these sequences, the containment release is due only to the in-vessel release. MAAP predicts less in-vessel release of these species due to the lower core temperatures calculated by MAAP as opposed to the data from which the ZISOR distributions are based upon. For the un-coolable sequences, MAAP generally under-predicts ZISOR by a smaller factor than in the coolable sequences since the Sr and Ba which were retained in the core debris are now available for release during CCI.

For the low-volatile lanthanum (La) and cerium (Ce) fission product species, both ZISOR and MAAP predict fairly low release fractions. For the coolable sequences, MAAP will generally under-predict the release fractions for those categories in which the predicted release fractions are more significant. This is consistent with the observation that MAAP tends to under-predict the in-vessel release with respect to ZISOR. For the un-coolable sequences, MAAP tends to slightly under-predict the La release and slightly over-predict the Ce release indicating a difference in volatilities for the La and Ce during CCI over what ZISOR predicts. Additionally, MAAP tends to over-predict the release fractions in the release categories with successful containment sprays indicating that the MAAP spray model assumes less wash-out of the low-volatile fission products.

For the ruthenium (Ru) fission product species, ZISOR assumes that the molybdenum (Mo) fission products will behave chemically similar to Ru, and thus Mo is included in the Ru group (see Table F.2-6). MAAP on the other hand treats Mo separately (as MoO2) and the MAAP Mo release fractions are reported in the Ru column. The MAAP Mo predictions are consistently higher than the ZISOR Ru predictions, which may indicate a different treatment of the Mo in MAAP than of the Ru in ZISOR.

In summary, ZISOR tends to predict higher release fractions than MAAP. This is most evident in the debris coolable sequences where the release is due solely to the in-vessel fission product release. For the debris un-coolable sequences, the differences between ZISOR and MAAP are usually smaller. In spite of the differences, both codes generally give credible predictions of release fractions. Differences between the two can be accounted for in the various modeling differences between MAAP and the computer codes and data on which the ZISOR distributions are based.

E.2.2.4.5.2 Source Term Release Timings

Figures F.2-8 through F.2-12 provide graphs of fission product release as a function of time. Note that these figures were generated by MAAP and will agree with the MAAP release fractions reported in Table F.2-8. Rather than present release timings for each release category in Table F.2-8, only representative release timings for Small Early; Large Early; Small Late; Large Late; and Bypass containment releases are given since timing differences for sequences within these categories are expected to be small. Further, only release timings for the noble gases, one volatile species (Iodine reported as CsI), one semi-volatile species (Strontium reported as SrO) and one low-volatile species (Lanthanum reported as La2O3) are reported since other species in the same volatility class would have similar release timings.

Figure F.2-8 shows the release timing of a Small, Early containment release. RC14 was used where vessel failure and containment failure occurred at about three hours. Release duration for all fission product species is about 60 hours after containment failure (although it is noted that the CsI fraction is just beginning to level out).

Figure F.2-9 shows the release timing of a Large, Early containment release. RC04 was used where vessel failure and containment failure occurred at about 18 hours. Release duration for all fission product species is about one hour after containment failure. Subsequent I and Cs release is due to revolatilization.

Figure F.2-10 shows the release timing of a Small, Late containment release. RC10 was used where vessel failure occurred at about 18 hours and containment failure occurred four hours later. Release duration for all fission product species is about 20 hours after containment failure.

Figure F.2-11 shows the release timing of a Large, Late containment release. RC06 was used where vessel failure occurred at about 18 hours and containment failure occurred four hours later. Release duration for all fission product species is about five hours after containment failure.

Figure F.2-12 shows the release timing of a containment Bypass release. The SGTR RC17 was used where the vessel failure occurred at about 19 hours. Environment release occurs before this at about the time of core damage (17 hours) with release duration of about three hours.

F.2.2.4.6 Insights from the Source Term Analysis

The release fractions (from ZISOR) for the top (highest annual frequency) five release categories are presented in a simplified format below:

Release Category	Frequency	Noble Gas	Volatiles	Non-Volatiles
RC10 / Small-Late	2.0e-05	1.0	4.7e-03	1.3e-04
RC12U / Small-Late	1.2e-05	1.0	3.8e-03	1.0e-03
RC21 / Basemat Failure	1.1e-05	1.0	4.8e-04	7.1e-06
RC19 / No Core Damage	1.0e-05	0.0	0.0	0.0
RC08U / Large-Late	8.1e-06	1.0	8.8e-02	2.5e-02

RC10 and RC12U are release categories in which the containment fails late (4 hours after vessel failure) with a small (< 3 inch diameter) failure. RC21 is a category in which core debris remains uncooled for so long that the concrete basemat is eroded (due to interaction with the core debris) totally through and modeled as a very late containment failure (> 24 hours after vessel failure). RC19 is a release category in which there was no severe core damage so the only release is the initial activity in the RCS which is taken to be negligible for this analysis. Finally, RC08U is a release category in which the containment fails late as in RC10 and RC12U above but fails with a large (> 7 ft^2) rupture.

It is observed that late containment failures are the most likely release categories and that they usually produce only small releases (< 1 percent volatile species). Of the five release categories presented above, only RC08U has what would be considered a "large" release with over 8 percent of the volatile species being released.

From Table F.2-8, it is observed that several release categories indicate very large releases (volatile releases between 20 percent and 69 percent). It is noted that these release categories are all Large, Early containment failures without containment spray. As expected, the frequencies for these release categories are relatively small (< 1.0E-06). The SGTR release category (RC17) is of particular note as well since this category represents a very large release (59 percent of volatiles) with a non-trivial frequency (1.5E-06). These results will be considered under the purview of a severe accident management strategy.

Also observed form Table F.2-8 is that operation of the containment spray system is very effective in removing fission products from the containment atmosphere. However, sprays also inhibit containment pressurization and subsequent failure which means that those release categories representing sequences with operable sprays will have relatively low frequencies. Therefore, even though sprays are very effective in reducing source terms, they play a relatively minor role in the overall source term evaluation.

F.2.3 PRA MODEL TECHNICAL ADEQUACY FOR SAMA

Pacific Gas & Electric Company (PG&E) employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA model for the operating PG&E nuclear generation plant. This approach includes both a proceduralized PRA maintenance and update process, and the use of self-assessments and independent peer reviews. The following information describes this approach as it applies to the Diablo Canyon Power Plant (DCPP) PRA.

F.2.3.1 PRA MAINTENANCE AND UPDATE

The PG&E risk management process ensures that the applicable PRA model remains an accurate reflection of the as-built and as-operated plants. This process is defined in the PG&E risk management program, which consists of a governing procedure PRA-ADM. This procedure delineates the responsibilities and guidelines for updating the full power internal events PRA models at the Diablo Canyon Power Plant. The overall PG&E risk management program, including PRA-ADM, defines the process for implementing regularly scheduled and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operational experience), and for controlling the model and associated computer files. To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plant, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model.
- New procedures and procedure changes are reviewed for their impact on the PRA model.
- New engineering calculations and revisions to existing calculations are reviewed for their impact on the PRA model.
- Equipment unavailabilities are captured, and their impact on CDF is trended.
- Plant specific initiating event frequencies, failure rates, and maintenance unavailabilities for equipment that can have a significant impact on the PRA model are updated approximately every 6 years. The last update was completed in March, 2003**.**

In addition to these activities, PG&E risk management procedures provide the guidance for particular risk management and PRA quality and maintenance activities. This guidance includes:

- Documentation of the PRA model, PRA products, and bases documents.
- The approach for controlling electronic storage of Risk Management (RM) products including PRA update information, PRA models, and PRA applications.
- Guidelines for updating the full power, internal and external events PRA models for the Diablo Canyon Power Plant.
- Guidance for use of quantitative and qualitative risk models in support of the On-Line Work Control Process Program for risk evaluations for maintenance tasks (corrective maintenance, preventive maintenance, minor maintenance, surveillance tests and modifications) on systems, structures, and components (SSCs) within the scope of the Maintenance Rule (10CFR50.65 (a)(4)).

In accordance with this guidance, regularly scheduled PRA model updates nominally occur on an approximately 4-year cycle; longer intervals may be justified if it can be shown that the PRA continues to adequately represent the as-built, as-operated plant. PRA model updates were also performed in shorter intervals in the past to incorporate design changes, procedure changes and/or newly developed industry data and models that may have a significant impact on the plant risk results. The most recent update of the DCPP PRA model (designated as DC01A) was completed in February 2009. This year PG&E has committed to complete the Internal Fire PRA, component database update and identify plant and procedural changes and perform a screening to determine their significance with respect to the potential impact on the PRA.

F.2.3.2 PRA SELF ASSESSMENT AND PEER REVIEW

Several assessments of technical capability have been made, and continue to be planned, for the DCPP PRA models. These assessments are as follows:

- An independent PRA peer review (certification) was conducted using the Westinghouse Owners Group (WOG) Peer Review Certification Guidelines in May, 2000 and the final report for the peer review was published in August, 2000 (Reference 45).
- In addition to the WOG Peer Review, recent limited scope and independent assessments of the DCPP Level 1 and Level 2 PRA models have been performed by leading industry PRA experts (i.e., Gap Analyses) to support several risk-informed applications, including the MSPI calculations and DCPP's transition to the National Fire Protection Association (NFPA) 805 Standard (Reference 14):
    1. Scientech/Jacobsen Engineering reviewed the Diablo Canyon Internal Flood PRA to identify any specific weaknesses in its approach or implementation which might impair its ability to be used for risk informed decision making (Reference 54). The approach for the review was to compare the method of implementation and documentation of the existing Internal Flooding PRA with the requirements of the ASME PRA standard Addendum B (March 17th 2005 Draft) (Reference 1).
    2. A self-assessment of the Diablo Canyon Level 1 Internal Events PRA was conducted by ERIN Engineering and Research, Inc. and the results were published in December 2006 (Reference 53) and then updated in January 2008 (Reference 58). One aim of the self-assessment is to identify Supporting Requirements (SR) for which the DCPP PRA may not meet the ASME PRA STD RA-Sb-2005 Capability Category II requirements.
    3. A follow-on peer review of the upgraded Human Reliability Analysis (HRA) was performed by ABS Consulting, Inc. The upgrade of the HRA was

performed in response to the findings of the WOG Peer Review. The findings were published in July 2007 (Reference 55).

4. The Level 2 portion of the DCPP PRA model was assessed by Westinghouse in support of the RITSTF Initiative 5-b. The findings and their resolution/disposition for DCPP were published in November 2007 (Reference 56).

- The DCPP PRA model results were evaluated in the PWR Owners Group PRA cross-comparisons study performed in support of the implementation of the mitigating systems performance indicator (MSPI) process (Reference 66). DCPP did not have any identified outliers as a result of the review.
- PG&E also tracks issues/problem/errors associated with the PRA model and plant design and procedure changes that affect the PRA model that were identified by the PRA engineers. These issues were recorded in the PRA Action Tracking Database. Depending on the safety significance of these issues, some of them were either addressed by updating the affected portion(s) of the PRA model immediately or disposed of during the periodic update of the PRA model. Open items will be addressed in future model updates.

Two "A" F&Os from the WOG Peer Review related to the human reliability analysis (HRA) were addressed by upgrading the methodology used for the evaluation. The upgraded HRA analysis was subjected to a focused peer review as indicated above. The “B” F&Os from the WOG Peer Review were addressed during model updates in support of the EDG Completion Time Extension (CTE) license amendment request (LAR), the LAR effort to extend the Completion Times (CTs) for several emergency core cooling system (ECCS) components, and the MSPI calculations. All the “B” F&Os had therefore been addressed and closed out with the completion of the current model of record (DC01A PRA model) and there are no outstanding issues (“B” F&Os) from the WOG Peer Review.

The results of the independent assessments of the DCPP Level 1 and Level 2 PRA models (i.e., Gap Analyses) by leading industry PRA experts are presented below. The open items from these assessments and their disposition with respect to the SAMA identification using the PRA results and SAMA evaluation using the PRA models are discussed in the sections below.

Most of the review comments/finding from the review the DCPP Internal Flood PRA was on the lack of documentation. There were a few issues/deficiencies from the review and recommendations made for improvement in some of the areas of the DCPP Internal Flooding PRA for the PRA to meet at least Capability Category II requirements. The impact of these issues on the SAMA evaluation is also provided below.

All the findings of the self-assessment of the Diablo Canyon Level 1 Internal Events PRA performed by ERIN Engineering and Research, Inc. have been resolved with the exception of three supporting requirements associated with the human reliability analysis. These HRA related findings were also confirmed via the focused HRA peer review performed by ABS Consulting, Inc.

The focused HRA peer review identified eighteen issues that did not meet category level II of the PRA Standard. Seven of these were documentation issues or did not affect the results of the application. The remaining eleven were subsequently either dispositioned or were demonstrated to have a negligible effect on the results of this application as discussed below.

There were several findings from the review (by Westinghouse) of the Level 2 portion of the DCPP PRA model. Recommended resolution/disposition of these findings was also provided by the reviewers. An evaluation of the impact of these findings on the SAMA identification using the PRA results and SAMA evaluation using the PRA model is discussed below.

Also provided below are discussions of the items from the DCPP PRA Action Tracking Database that have not been disposed and may potentially affect the risk results from the DCPP PRA model.

DCPP plans to dispose those open items/unresolved issues pertaining to HRA, and unresolved issues from the DCPP PRA Action Tracking Database this year and those pertaining to the Internal Flooding analysis and Level 2 analysis in the following year.

F.2.3.3 GENERAL CONCLUSION REGARDING PRA CAPABILITY

The DCPP PRA maintenance and update processes and technical capability evaluations described above provide a robust basis for concluding that the PRA is suitable for use in the risk-informed portion of the SAMA licensing actions. As specific risk-informed PRA applications are performed, remaining gaps to specific requirements in the PRA standard will be reviewed to determine which, if any, would merit application-specific sensitivity studies in the presentation of the application results.

F.2.3.4 ASSESSMENT OF PRA CAPABILITY NEEDED FOR SAMA IDENTIFICATION AND EVALUATION

To determine the impact of the PRA peer review and gap analyses “open issues” on the Phase I SAMA identification process, the use of the PRA results in this process (and in particular, the use of a list of PRA model events generated from the PRA results) is discussed first. DCPP plant-specific PRA-derived risk significance information is used in this evaluation. The impact of these open issues on the PRA model events is then evaluated.

The initial list of SAMA candidates for DCPP was developed from a combination of resources such as the DCPP PRA results, Industry Phase 2 SAMAs, etc. These resources are judged to provide a list of potential plant changes that are most likely to reduce risk in a cost-effective manner for DCPP.

The DCPP PRA was used to generate a list of model events (split fractions of the PRA model) sorted according to their risk reduction worth (RRW) values with respect to CDF. The split fractions in this list are those events that would provide the greatest reduction in the DCPP CDF if the failure probability were set to zero. The events were reviewed down to the risk significant threshold of 1.02 for non-fire/non-seismic events, and 1.03 and 1.01 for fire and seismic events, respectively. This breakdown addresses all events that could be correlated to an averted cost-risk of >$100,000).

Table F.5-1a documents the disposition of each non-seismic / non-fire event in the Level 1 DCPP importance list with RRW values of 1.02 or greater. Plant fire and seismic-induced CDF events are addressed in Tables F.5-1b and F.5-1c, respectively. Fire events are analyzed down to an RRW of 1.03 while seismic events were examined further to 1.01. Refer to Section F.5.1.1 for explanation of RRW review thresholds variation. Note that the review of each event involves a detailed evaluation of the sequences including the event to identify the factors that make the event important

A similar review was performed on the importance listings of split fractions from the DCPP PRA Level 2 results. In this case, a composite importance based on the following release categories was used to identify potential SAMAs:

- ST1/ST5: Large Early Release and Releases associated with Interfacing System LOCA
- ST2/ST4: Small Early Release and Containment Bypass with AFW available

As with the Level 1 non-seismic / non-fire internal review, the disposition of the Level 2 results included those events with an RRW greater than or equal to 1.02. Tables F.5-2a and F.5-2b document those events associated with release categories ST1/ST5 and ST2/ST4, respectively.

Table F.5-3 summarizes the SAMAs identified in Tables E-5-1 (a,b,c) and 5-2 (a,b) based on the PRA results (model events/split fractions with RRW values ≥ 1.01) and the associated DCPP PRA system, operator action, etc. whose RRW values were used in the identification of SAMAs for DCPP.

The next step in the determination of the technical adequacy of the PRA results used in the SAMA identification process is the evaluation of the impact of the “open items/issues” from the peer review, gap analyses and the PRA Action Tracking database on the PRA system, operator action, etc. that were considered in the SAMA identification process. A summary listing of these PRA systems, operator actions, etc. are shown below:

- Operator actions: (1) to cooldown and depressurize the RCS, (2) to isolate a ruptured steam generator, and (3) to switchover to sump recirculation mode after a Small, Medium or Large LOCA event
- DC power system
- Emergency diesel generators
- AFW pumps and electric power (AC/DC) support
- Switchgear room ventilation system

- Instrument air to PORV 474
- CCW pumps and electric power (AC/DC) support
- Cable spreading room and control room fire events
- Containment phenomenological event

The evaluation of the impact of the open items/issues on the above systems, operator actions, etc., are provided in Addendum 1. If the open item/issue is involved with a system or operator action for which a SAMA has been identified, then the open item/issue will have no impact on the conclusion of the SAMA identification process. If an open item/issue does not have a significant impact or has a conservative impact on the risk results (CDF/LERF), then it will have an insignificant impact on the RRW values of the above modeled system, operator actions, etc. Since the RRW values were used to determine the importance of the model events/split fractions with respect to the identification of potential SAMA, the open item/issue will also have an insignificant impact on the SAMA identification process and the conclusion of the process.

F.2.3.5 CONCLUSION REGARDING PRA CAPABILITY FOR SAMA IDENTIFICATION AND EVALUATION

The DCPP PRA model DC01A results are suitable for use as a resource in the SAMA identification process. This conclusion is based on:

- The PRA maintenance and update processes in place
- The PRA technical capability evaluations that have been performed and are being planned
- The SAMA identification process uses the RRW values of PRA model events/split fractions that are associated with system, operator action, etc.

Although the peer review and gap analyses “open items/issues” will be resolved in future model updates, they have insignificant impact on the conclusion of this process.

F.3 LEVEL 3 RISK ANALYSIS

This section addresses the key input parameters and analysis of the Level 3 portion of the risk assessment. In addition, Section F.7.3 summarizes a series of sensitivity evaluations to potentially critical parameters.

F.3.1 ANALYSIS

The MACCS2 code (Reference 22) was used to perform the Level 3 probabilistic risk assessment (PRA) for Diablo Canyon Power Plant (DCPP). The input parameters given with the MACCS2 “Sample Problem A,” formed the basis for the present analysis. These generic values were supplemented with parameters specific to DCPP and the surrounding area. Site-specific data included population distribution, economic parameters, and meteorological data. Generic economic parameters for the costs of evacuation, relocation and decontamination were escalated from the time of their formulation (1986) to more recent (August 2008) costs. Plant-specific release data included release frequencies and the time-dependent distribution of nuclide releases from 6 accident sequences at DCPP. The behavior of the population during a release (evacuation parameters) was based on plant and site-specific set points (i.e., declaration of a General Emergency) and evacuation time estimates (Reference 67). These data were used in combination with site specific meteorology to calculate risk impacts (exposure and economic) to the surrounding (within 50 miles) population.

The NRC sponsored the development of the MACCS code as a successor to the CRAC2 code for the performance of commercial nuclear industry probabilistic safety assessments (PSAs). The MACCS code was used in the NUREG-1150 PSA study (Reference 19) in the early 1990's. Prior to being released to the public, MACCS was independently verified by Idaho National Engineering and Environmental Laboratory (Reference 6). The use of the MACCS2 code is consistent with NEI 05-01, as endorsed by LR-ISG-2006-03.4 (Reference 26). The MACCS2 methodology has been employed in numerous applications, including in WASH-1400 (NUREG-75/014, Reactor Safety Study (1975)) (Reference 17) and NUREG-1150 (Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants), for assessing impacts of postulated severe accidents for nuclear power plants. MACCS2 code is being used in a slightly updated fashion to support the current state-of-the-art reactor consequence analysis (SOARCA) being performed by the NRC. Moreover, the Gaussian plume model employed in the DCPP MACCS2 analysis is the standard atmospheric plume model used for nuclear safety and environmental evaluations for numerous regulatory applications. It is the underlying radiological dispersion and consequence model underpinning NRC Regulatory Guide 1.194 (Reference 24), Regulatory Guide 1.145 (NUREG/CR-2260) (Reference 18), and DOE-STD-3009-94, Appendix A (Reference 7) for NRC and DOE nuclear safety analyses.

The MACCS2 Gaussian plume model has been shown to provide results that are in good agreement, and generally conservative, when compared with more sophisticated models that address variable meteorological and terrain effects For example, one study performed by the Idaho National Laboratory released a tracer and then measured the air concentrations of the tracer. The results were compared with three different atmospheric transport models - two versions of the Gaussian model and a more sophisticated wind field and terrain sensitive Atmospheric Release Advisory Capability ("ARAC") code developed at Lawrence Livermore National Laboratory. The comparison showed that the Gaussian model provided significantly more conservative results than the actual dose measured by the field equipment as well as the maximum dose predicted by the more sophisticated wind and terrain sensitive ARAC code. Another study compared the MACCS2 code to a fully three dimensional code that accounted for terrain changes and the spatial variability of weather. The comparison showed that the results from the MACCS2 code were in reasonably good agreement with those obtained from the three dimensional model.

Mollenkamp et al. (Reference 12) compared several codes for recorded data in a terrain changing location in the Midwest. This study compared MACCS2 to a fully three-dimensional (3-D) code (which possesses the ability to take into account terrain changes and spatial variability of weather), at a series of one-mile wide arcs at various distances downwind over a distance of 100 miles. The results showed reasonably good agreement obtained with MACCS2 compared to the three-dimensional Lagrangian operational dispersion integrator (LODI) model. The study concluded that, compared to LODI, MACCS2 predicts a more rapid decrease of exposure with distance and that this should be considered for estimating consequences at distances greater than 200 miles. The analysis distance of 50 miles used for the SAMA analysis is well within this range of acceptability based on this code comparison, and in general should provide nominally conservative results (compared to LODI) due to the greater deposition closer to the source.

Nuclear safety SAMA regional analyses require running a significant number of weather trials to obtain robust statistical results. The MACCS2 code is a flat-earth Gaussian plume models that can meet the computational demands of calculating many kinds of consequence results, with the appropriate level of statistical sampling. In contrast, computer codes that can accommodate multiple-station data so as to be able to model spatial variation of wind speed and direction (e.g., mesoscale models) and thus provide regional consequences would be impractical for analyzing the large number of weather sequences needed for SAMA analyses. The computer code for SAMA analysis must analyze numerous weather records at a minimum to calculate statistically meaningful results, and thereby provide plant insights with respect to many different site-specific weather sequences, rather than time-intensive modeling of only a few sequences. Use of other codes for this purpose is not practical given statistical requirements and the amount of input data necessary to fully account for off-site exposure and economic costs.

MACCS2 is generally unique among currently supported dispersion analysis modeling codes for its ability to address three required elements for SAMA analysis, that being (1) atmospheric dispersion of releases, (2) prompt and long term radiological health impacts (e.g., population dose), and (3) economic impacts. Various dispersion codes are available for analyzing chemical releases, such as CALPUFF & AERMOD which are preferred codes for EPA purposes, but these codes are not able to address the second and third elements of radiological health impacts and economic impacts needed to support a SAMA evaluation. Similarly, a variety of other dispersion codes exist for use for emergency planning purposes in the nuclear field, but these codes do not address long term radiological health impacts or prompt or long term costs. Only MACCS2 addresses the three required elements to support the regional analysis for cost-benefit considerations. For these reasons, MACCS2 is the only code specifically named as an acceptable methodology for estimating environmental consequences of severe accident analysis in the NRC Environmental Standard Review Plan, NUREG-1555 (Reference 27).

Regarding terrain variability, it is noted that the DCPP site is surrounded on the land portion by complex mountainous type terrain. The DCPP FSAR (Reference 52) Section 2.3.6 summarizes the investigation of the impacts of the local geography on airborne releases as follows:

> Despite the prevalence of the marine inversions and the northwesterly wind flow gradient along the California coast in the dry season, the long-term accumulation of plant emission, released routinely or accidentally, in any particular geographical area downwind from the plant is virtually impossible. Pollutants injected into the marine inversion layer of the coastal wind regime are transported and dispersed by a complex array of land-sea breeze regimes that exist all along the coast wherever canyons or valleys indent the coastal range. Because of the complexities of the wind circulation in these regimes and their fundamental diurnal nature, the net result is a very effective and wide daily dispersal of any pollutants that are present in the marine coastal air.

The MACCS2 analysis performed for SAMA seeks to evaluate the average (i.e., mean) consequences associated with a radiological release. While the uncertainty band associated with the consequence results for any single release could be postulated to be greater due to the complex terrain (e.g., a mountain valley channeling a release to a population center), the affect on the mean consequence results is expected to be minor.

Additionally, it is noted that the complex mountainous terrain would be expected to increase the amount of deposition close to the site due to impaction and potentially reduce the radiological material reaching population centers located further from the site.

Based on the above considerations, the use of the Gaussian model implemented in MACCS2 is judged acceptable for the development of dose risk and cost risk inputs into SAMA.

F.3.2 POPULATION

The population surrounding the DCPP site is estimated for the year 2045.

The population distribution projection for year 2045 was based on DCPP FSAR, Section 2.1.3 (Reference 52) data for year 2000 (census data) and FSAR population growth projections for year 2025. The FSAR growth rates were applied to achieve a year 2045 estimate. The baseline population was determined for each of 160 spatial elements, consisting of sixteen directions (i.e., N, NNE, NE,…NNW) for each of ten concentric distance rings with outer radii at 1, 2, 3, 4, 5, 10, 20, 30, 40 and 50 miles surrounding the site. The population data represents the combined resident and transient population for the region within 10 miles of the site, and the residential population only for the region of 10 to 50 miles from the site.

The total year 2045 population for the 160 spatial elements in the region is estimated at 1,192,750. The distribution of the population is given for the 10-mile radius and the 50-mile radius from DCPP in Tables F.3-1 and F.3-2, respectively.

F.3.3 ECONOMY

MACCS2 requires certain agricultural based economic data (fraction of land devoted to farming, annual farm sales, fraction of farm sales resulting from dairy production, and property value of farm and non-farm land) for each of the 160 spatial elements. This data can be generated by SECPOP2000 (Reference 23), but due to recent errors discovered with the economic parameter processing of the SECPOP2000 code, SECPOP2000 was not utilized to develop the economic parameters for the DCPP analysis. Instead, the economic parameters were developed manually using data in the 2002 National Census of Agriculture (Reference 63) and from the Bureau of Economic Analysis (Reference 2) for each of the 4 counties surrounding the plant, to a distance of 50 miles. The values used for each of the 160 spatial elements were the data from each of the surrounding counties multiplied by the fraction of that county's area that lies within that sector. Region-wide wealth data (i.e., farm wealth and non-farm wealth) were based on county-weighted averages for the region within 50-miles of the site using data in the 2002 National Census of Agriculture (Reference 63) and the Bureau of Economic Analysis (Reference 2). The portion of each county within 50-miles of the site was accounted for in the calculation. Values were escalated using the consumer price index from the Bureau of Labor Statistics (Reference 64) to August 2008 equivalent values.

In addition, generic economic data that is applied to the region as a whole were revised from the MACCS2 sample problem input in order to account for cost escalation since 1986, the year that input was first specified. A factor of 2.00, representing cost escalation from 1986 to August 2008 using the consumer price index (Reference 64) was applied to parameters describing cost of evacuating and relocating people, land decontamination, and property condemnation

MACCS2 economic parameters utilized in the DCPP analysis include the following:

DCPP MACCS2 Economic Parameters

Variable	Description	DCPP Value
DPRATE[1]	Property depreciation rate (per yr)	0.20
DSRATE[2]	Investment rate of return (per yr)	0.07
EVACST[3]	Daily cost for a person who has been evacuated ($/person-day)	54.00
POPCST[3]	Population relocation cost ($/person)	10,000
RELCST[3]	Daily cost for a person who is relocated ($/person-day)	54.00
CDFRM0[3]	Cost of farm decontamination for various levels of decontamination ($/hectare)	1,125 2,500
CDNFRM[3]	Cost of non-farm decontamination per resident person for various levels of decontamination ($/person)	6,000 16,000
DLBCST[3]	Average cost of decontamination labor ($/man-year)	70,000
VALWF0[4]	Value of farm wealth ($/hectare)	8,558
VALWNF[4]	Value of non-farm wealth ($/person)	267,909

(1) DPRATE uses NUREG/CR-4551 value (Reference 20).
(2) DSRATE based on NUREG/BR-0058 (Reference 25).

(3) These parameters for DCPP use the NUREG/CR-4551 values (Reference 20), updated to August 2008 using the consumer price index. For CDFRM0 and CDNFRM, two values are utilized, one for each of two levels of modeled decontamination (i.e., dose reduction factors of 3 and 15).

(4) VALWF0 and VALWNF are based on 2002 National Agriculture Census (Reference 63) and Bureau of Economic Analysis data (Reference 2), updated to the August 2008 using the consumer price index.

F.3.4 FOOD AND AGRICULTURE

Food ingestion is modeled using the new MACCS2 ingestion pathway model COMIDA2 (Reference 22), consistent with Sample Problem A. The COMIDA2 model utilizes national based food production parameters derived from the annual food consumption of an average individual such that site specific food production values are not utilized. The fraction of population dose due to food ingestion is typically small compared to other population dose sources. For DCPP, about one percent of the total population dose is due to food ingestion.

F.3.5 NUCLIDE RELEASE

The core inventory at the time of the accident is based on a plant specific evaluation and corresponds to the end-of-cycle values for DCPP operating at 3411 MWt, the current licensed value. Table F.3-3 summarizes the estimated DCPP core inventory used in the MACCS2 analysis (Reference 59).

DCPP nuclide release categories, as determined by the MAAP computer code, are related to the MACCS2 categories as shown in Table F.3-4. Releases were modeled as occurring at the top of the reactor building (67 meters). Note that minor adjustment to the containment height based on site grade changes has negligible impact on results. The thermal content of each of the releases was assumed to be the same as ambient, i.e., buoyant plume rise was not modeled. Each of these assumptions was considered in sensitivity analyses, presented in Section F.7.3.

Release frequencies, nuclide release fractions (of the core inventory), shown in Table F.3-6, and the time distribution of the release were analyzed to determine the sum of the exposure (50-mile dose) and economic (50-mile economic costs) risks from 6 accident sequences (also given in Table F.3-6). Each accident sequence was chosen to represent a set of similar accidents. Representative MAAP cases for each of the release categories were chosen based on a review of the Level 2 model cutsets and the dominant types of scenarios that contributed to the results. A brief description of each of those MAAP cases is provided in Table F.3-5, and a summary of the release magnitude and timing for those cases is provided in Table F.3-6. Multiple release duration periods (i.e., plume segments) were defined which represent the time distribution of each category's releases.

F.3.6 EVACUATION

Reactor trip for each sequence was taken as time zero relative to the core containment response times. A General Emergency (GE) is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. For the DCPP analysis the time of the GE declaration was estimated based on the DCPP emergency action levels (Reference 60). The declaration times are presented in Table F.3-6.

The MACCS2 User's Guide input parameters of 95 percent of the population within 10 miles of the plant evacuating and 5 percent not evacuating were employed. These values are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the EPZ (Reference 19).

The evacuees are assumed to begin evacuation 75 minutes after a general emergency has been declared at a base evacuation radial speed of 0.4 m/sec. This time to begin evacuation and the base speed is derived from the site specific evacuation study (Reference 67). The evacuation speed is a time-weighted average value accounting for season, day of week, time of day, and weather conditions. The evacuation parameters were considered further in the sensitivity analyses presented in Section F.7.3.

F.3.7 METEOROLOGY

Annual hourly meteorology DCPP data sets from 2002 through 2006 were investigated for use in the MACCS2 analysis. Of the hourly data of interest (10-meter wind speed, 10-meter wind direction, multi-level temperatures used to calculate stability class, and precipitation), year 2003 and 2005 data had a significant number of data voids compared to the other years of data and were therefore not finalized. Traditionally, up to 10 percent of missing data is considered acceptable. MACCS2 requires complete sequential hourly data, therefore missing data must be estimated. Data gaps were filled by (in order of preference): interpolation (if the data gap was less than 6 hours), or using data from the same hour and a nearby day (substitution technique). The 10-meter wind speed and direction were combined with precipitation and atmospheric stability (derived from the vertical temperature gradient) to create the hourly data file for use by MACCS2. Precipitation data was derived from the California Irrigation Management Information System (CIMIS). Site 52 located at California Polytechnic State University in San Luis Obispo (35.31N, -120.66W) about 13 miles from DCPP served as the primary precipitation data site. Site 160 located (35.34N, -120.73W) about 11 miles from DCPP served as a secondary precipitation data site to fill in missing data.

The 2002 meteorological data set was found to result (see Section F.7.3 for discussion of sensitivity analysis) in the largest economic cost risk and dose risk compared to the 2004 and 2006 data sets, and the initial 2002 data set had an acceptable amount of data voids (about 5 percent). Therefore, the 2002 hourly meteorology was selected as the base case.

Atmospheric mixing heights were specified for AM and PM hours for each season of the year. These values ranged from 500 meters to 900 meters. (Reference 8)

F.3.8 MACCS2 RESULTS

Table F.3-7 shows the mean off-site doses and economic impacts to the region within 50 miles of DCPP for each of 6 release categories calculated using MACCS2. The mean off-site dose impacts are multiplied by the annual frequency for each release category and then summed to obtain the dose-risk and offsite economic cost-risk (OECR) for each unit. Table F.3-7 provides these results.

F.4 BASELINE RISK MONETIZATION

This section explains how DCPP calculated the monetized value of the status quo (i.e., accident consequences without SAMA implementation). DCPP also used this analysis to establish the maximum benefit that could be achieved if all on-line DCPP risk were eliminated, which is referred to as the Maximum Averted Cost-Risk (MACR). Per the site PRA model (designated DC01A), the internal events CDF of 8.44E-06 (at an average truncation of 1E-14/yr) was used for the calculations in the following sections. External risk is addressed in Section F.4.6.2.

F.4.1 OFF-SITE EXPOSURE COST

The baseline annual off-site exposure risk was converted to dollars using the NRC's conversion factor of $2,000 per person-rem, and discounted to present value using NRC standard formula (Reference 21):

$$W_{pha} = C \times Z_{pha}$$

Where:

W_{pha} = monetary value of public health accident risk after discounting

C = $[1-\exp(-rt_f)]/r$

t_f = years remaining until end of facility life = 20 years

r = real discount rate (as fraction) = 0.03 per year

Z_{pha} = monetary value of public health (accident) risk per year before discounting ($ per year)

The Level 3 analysis showed an annual off-site population dose risk of 8.79 person-rem. The calculated value for C using 20 years and a 3 percent discount rate is approximately 15.04. Therefore, calculating the discounted monetary equivalent of accident dose-risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value (15.04). The calculated off-site exposure cost is $264,515.

F.4.2 OFF-SITE ECONOMIC COST RISK

The Level 3 analysis showed an annual off-site economic risk of $33,699. Calculated values for off-site economic costs caused by severe accidents must be discounted to present value as well. This is performed in the same manner as for public health risks and uses the same C value. The resulting value is $506,820.

F.4.3 ON-SITE EXPOSURE COST RISK

Occupational health was evaluated using the NRC recommended methodology that involves separately evaluating immediate and long-term doses (Reference 21).

For immediate dose, the NRC recommends using the following equation:

Equation 1:

$$W_{IO} = R\{(FD_{IO})_S - (FD_{IO})_A\}\{[1 - \exp(-rt_f)]/r\}$$

Where:

W_{IO} = monetary value of accident risk avoided due to immediate doses, after discounting

R = monetary equivalent of unit dose ($2,000 per person-rem)

F = accident frequency (events per year) (8.44E-06 (internal events CDF)) at an average 1E-14/yr truncation

D_{IO} = immediate occupational dose [3,300 person-rem per accident (NRC estimate)]

$_S$ = subscript denoting status quo (current conditions)

$_A$ = subscript denoting after implementation of proposed action

r = real discount rate (0.03 per year)

t_f = years remaining until end of facility life (20 years).

Assuming F_A is zero, the best estimate of the immediate dose cost is:

$$W_{IO} = R\,(FD_{IO})_S\{[1 - \exp(-rt_f)]/r\}$$

$$= 2{,}000 * 8.44\text{E-}06 * 3{,}300 * \{[1 - \exp(-0.03 * 20)]/0.03\}$$

= \$838

For long-term dose, the NRC recommends using the following equation:

Equation 2:

$$W_{LTO} = R\{(FD_{LTO})_S - (FD_{LTO})_A\}\{[1 - \exp(-rt_f)]/r\}\{[1 - \exp(-rm)]/rm\}$$

Where:

W_{LTO} = monetary value of accident risk avoided long-term doses, after discounting, \$

D_{LTO} = long-term dose [20,000 person-rem per accident (NRC estimate)]

m = years over which long-term doses accrue (as long as 10 years)

Using values defined for immediate dose and assuming F_A is zero, the best estimate of the long-term dose is:

$$W_{LTO} = R\,(FD_{LTO})_S\,\{[1 - \exp(-rt_f)]/r\}\,\{[1 - \exp(-rm)]/rm\}$$

$$= 2{,}000*8.44\text{E-}06*20{,}000*\{[1 - \exp(-0.03*10)]/0.03\}\,\{[1 - \exp(-0.03*10)]/0.03*10\}$$

$$= \$4{,}386$$

The total occupational exposure is then calculated by combining Equations 1 and 2 above. The total accident related on-site (occupational) exposure risk (W_O) is:

$$W_O = W_{IO} + W_{LTO} = (\$838+\$4{,}386) = \$5{,}224$$

F.4.4 ON-SITE CLEANUP AND DECONTAMINATION COST

The total undiscounted cost of a single event in constant year dollars (C_{CD}) that NRC provides for cleanup and decontamination is \$1.5 billion (Reference 21). The net present value of a single event is calculated as follows. NRC uses the following equation to integrate the net present value over the average number of remaining service years:

$$PV_{CD} = [C_{CD}/mr][1-\exp(-rm)]$$

Where:

PV_{CD} = net present value of a single event

C_{CD} = total undiscounted cost for a single accident in constant dollar years

r = real discount rate (0.03)

m = years required to return site to a pre-accident state

The resulting net present value of a single event is $1.3E+09. The NRC uses the following equation to integrate the net present value over the average number of remaining service years:

$$U_{CD} = [PV_{CD}/r][1-\exp(-rt_f)]$$

Where:

PV_{CD} = net present value of a single event ($1.3E+09)

r = real discount rate (0.03)

t_f = 20 years (license renewal period)

The resulting net present value of cleanup integrated over the license renewal term, $1.95E+10, must be multiplied by the internal events CDF (8.44E-06) to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is $164,491.

F.4.5 REPLACEMENT POWER COST

Long-term replacement power costs were determined following the NRC methodology in NRC 1997. The net present value of replacement power for a single event, PV_{RP}, was determined using the following equation:

$$PV_{RP} = [\$1.2\times10^{8}/r] * [1 - \exp(-rt_f)]^2$$

Where:

PV_{RP} = net present value of replacement power for a single event, ($)

r = 0.03

t_f = 20 years (license renewal period)

To attain a summation of the single-event costs over the entire license renewal period, the following equation is used:

$$U_{RP} = [PV_{RP} / r] * [1 - \exp(-rt_f)]^2$$

Where:

U_{RP} = net present value of replacement power over life of facility ($-year)

After applying a correction factor to account for Diablo Canyon's size relative to the "generic" reactor described in NUREG/BR-0184 (Reference 21) (i.e., 1138 megawatt electric / 910 megawatt electric), the replacement power costs are determined to be 6.91E+09 ($-year). Multiplying 6.91E+09 ($-year) by the CDF (8.44E-06) results in a replacement power cost of $58,318.

F.4.6 MAXIMUM AVERTED COST-RISK

The DCPP MACR is the total averted cost-risk if all internal and external events risk associated with on-line operation were eliminated. This is calculated by summing the following components:

- Maximum Internal Events Averted Cost-Risk
- Maximum External Events Averted Cost-Risk

As described in Section F.5.1, the MACR is used in the SAMA identification process to determine the depth of the importance list review. In addition, the MACR is used in the Phase I analysis as a means of screening SAMAs. The following subsections provide a description of how each of these components is calculated and used together to obtain the DCPP MACR.

F.4.6.1 INTERNAL EVENTS MAXIMUM AVERTED COST-RISK

The maximum internal events averted cost-risk is the sum of the contributors calculated in Sections F.4.1 through F.4.5:

Maximum Averted Internal Events Cost-Risk

Off-site exposure cost	$264,515
Off-site economic cost	$506,820
On-site exposure cost	$5,224
On-site cleanup cost	$164,491
Replacement power cost	$58,318
Total cost (per unit)	$999,368

This total represents the per unit monetary equivalent of the risk that could be eliminated if all risk associated with on-line internal event hazards (including internal floods) could be eliminated for DCPP. The internal events MACR is rounded to next highest thousand ($1,000,000) for SAMA calculations. It should be noted that the Phase II cost benefit calculations account for the difference between the rounded MACR and the actual MACR by adding the difference to the averted cost-risk calculated for each SAMA.

F.4.6.2 EXTERNAL EVENTS MAXIMUM AVERTED COST-RISK

The maximum averted cost-risk for external events must be quantified for the cost benefit calculations; however, this cost-risk must be estimated based on information in the IPEEE given that complete, current, quantifiable external events models are not available for all types of events. As described in Sections F.5.1.5 and F.5.1.6, some changes have been made to these models, but they have not been updated to reflect recent plant changes or the full spectrum of current PRA techniques. Therefore, the absolute CDF values that are included in the IPEEE would generally not be considered to be directly comparable to the results of the internal events PRA model. As a result, an alternate method of accounting for the external events contributions must be established.

The method chosen to account for external events contributions in the SAMA analysis is to use a multiplier on the internal events results. In previous SAMA analyses, it has been assumed that the risk posed by external events and internal events is approximately equal. This assumption is not unreasonable unless available analyses indicate that there are external events contributors that present a disproportionate risk to the site. Based on a review of the DCPP external events results, it was observed that both fire and seismic contributors were disproportionately dominant when compared to all external events. Hence, development of a multiplier representative of actual external risk was deemed necessary.

This is simply the ratio of total CDF (including internal and external) to only internal CDF. This ratio is called the External Events multiplier and its value is calculated as follows:

EE Multiplier = (8.44E-06+5.42E-05) / (8.44E-06) = 7.4

The contributions of the external events initiators are summarized in the following table:

IPEEE Contributor Summary External Event Initiator Group CDF

Fire	1.39E-05
Seismic	3.77E-05
High Winds	3.20E-07
Transportation & Nearby Facility – ship impact	1.90E-08
Transportation & Nearby Facility - accidental aircraft impact	7.00E-07
External Flooding	7.20E-07
Chemical Release	8.00E-07
Total EE CDF	**5.42E-05**

F.4.6.3 DCPP MAXIMUM AVERTED COST-RISK

As stated in Section F.4.6, the MACR is the total of these two components:

Internal Events	=	$1,000,000
External Events	=	$6,400,000
Single Unit Maximum Averted Cost-Risk	=	$7,400,000

The MACR and implementation costs are considered on a per-unit scale for consistency (unless otherwise noted). Any "economy of scale" that may exist in the implementation costs have been accounted for given that the implementation costs were originally developed on a site basis and then divided by 2 for use in the net value calculations.

F.5 PHASE 1 SAMA ANALYSIS

The Phase 1 SAMA analysis, as discussed in Section F.1, includes the development of the initial SAMA list and a coarse screening process. This screening process eliminated those candidates that are not applicable to the plant's design or are too expensive to be cost beneficial even if the risk of on-line operations were completely eliminated. The following subsections provide additional details of the Phase 1 process.

F.5.1 SAMA IDENTIFICATION

The initial list of SAMA candidates for DCPP was developed from a combination of resources. These include the following:

- DCPP PRA results and PRA Group Insights
- Industry Phase 2 SAMAs (review of potentially cost effective Phase 2 SAMAs from selected plants)
- DCPP Individual Plant Examination IPE (Reference 33)
- DCPP IPEEE (Reference 37)

These resources are judged to provide a list of potential plant changes that are most likely to reduce risk in a cost-effective manner for DCPP.

In addition to the "Industry Phase 2 SAMA" review identified above, an industry based SAMA list was used in a different way to aid in the development of the DCPP plant specific SAMA list. While the industry Phase 2 SAMA review cited above was used to identify potential SAMAs that might have been overlooked in the development of the DCPP SAMA list due to PRA modeling issues, a generic SAMA list was used to help identify the types of changes that could be used to address the areas of concern identified through the DCPP importance list review. For example, if Instrument Air availability was determined to be an important issue for DCPP, the industry list would be reviewed to determine if a plant enhancement had already been conceived that would address DCPP's needs. If an appropriate SAMA was found to exist, it would be used in the DCPP list to address the Instrument Air issue; otherwise, a new SAMA would be developed that would meet the site's needs. This generic list was compiled as part of the development of multiple industry SAMA analyses and is available in NEI 05-01 (Reference 13).

It should be noted that the process used to identify DCPP SAMA candidates focuses on plant specific characteristics and is intended to address only those issues important to the site. In this case, the existing capabilities of the plant preclude the need to include many of the potential SAMAs that have been identified for other PWRs. As a result, because of the effectiveness of past plant reviews and subsequent modifications the types of changes that might be cost effective for DCPP are reduced and the SAMA list is relatively short.

F.5.1.1 LEVEL 1 DCPP IMPORTANCE LIST REVIEW

The importance list review was performed to identify the failure scenarios most important to DCPP risk and to develop methods to mitigate those scenarios. For each event on the importance list, the reasons for the event's importance are determined through sequence and systems analysis. Strategies to mitigate the relevant failures are developed based on accident sequence review, plant knowledge, and industry insights. For DCPP, importance lists were developed for the internal events, fire, and seismic models.

The importance lists themselves are developed from the DCPP PRA results files and are comprised of the model's split fractions sorted according to their risk reduction worth (RRW) values. The events with the largest RRW values in this list are those events that would provide the greatest reduction in the CDF if the failure probability were set to zero. Because a PRA's importance list can be extensive, it is desirable to limit the review to only those contributors that could yield potentially cost beneficial results. One method that can be used to limit the scope of the importance list review is to correlate the RRW value threshold to the lowest expected cost of implementation for a SAMA. Usually, operator actions in the form of procedure changes are among the least expensive enhancements that can be made at a site, so they are often used as the representative "lowest cost SAMA". For DCPP, operator actions were considered as potential SAMA candidates and documented in Tables F.5-1 (a,b,c) and F.5-2 (a,b).

The cost of a procedure change varies depending on the type of procedure that is being changed, the scope of the changes that are proposed, and the training program changes, but the lower end of the cost estimates range from $50,000 to $100,000 (Reference 5). For DCPP, the upper end of this range ($100,000) is used as the lowest cost SAMA to account for engineering analysis, the update of procedure text and supporting documentation, and training for both units.

The RRW value corresponding to $100,000 was developed for the internal events, fire, and seismic models as follows:

- Internal Events: 1.04
- Fire: 1.03
- Seismic: 1.01

For the internal events model, this can be demonstrated by reducing the CDF, dose-risk and OECR by a factor of 1.04, which corresponds to an event with Level 1- and Level 2-based RRW values of 1.04. The corresponding single unit averted cost-risk would be $49,965. Applying a factor of 2 to account for both units results in a cost-risk of $99,930. This is approximately equal to the assumed minimum expected cost of implementation of $100,000. Due to changes in Level 2 model results after the importance list review process began, importance list reviews were performed down to the 1.02 RRW level and the information was conservatively retained for the analysis.

For the fire analysis, RRW threshold was derived using the assumption that the fire CDF is directly proportional to its component of the MACR. Once the fire component of the MACR is defined for the site, the factor by which the MACR is reduced by $100,000 is defined to be the RRW review threshold. For DCPP, the fire contribution to the MACR is defined as follows:

Fire Contribution to MACR = (Site MACR – Site MACR/EE Multiplier) * (site Fire CDF/ site EE CDF)

OR

Fire Contribution to MACR = ($14,800,000 - $14,800,000/7.4) * (2.78E-05/1.08E-04) = $3,294,815

The RRW threshold is then calculated by dividing the fire contribution to the MACR by the fire contribution to the MACR minus $100,000:

RRW Threshold = $3,294,815 / $3,194,815 = 1.03

The process to establish the seismic RRW threshold is the same, but with the site seismic CDF being 7.54E-05, the threshold is 1.01.

Table F.5-1a documents the disposition of each split fraction in the Level 1 internal events DCPP RRW list with RRW values of 1.02 or greater. Similarly, Tables F.5-1b and F.5-1c contain the importance list review results (down to RRWs calculated above) for the Fire and Seismic models, respectively. The depth of the RRW review is consistent with NEI 05-01 guidance as well as other SAMA analyses. Note that the review of each split fraction involves an evaluation of the sequences including the split fraction to identify the factors that make the split fraction important.

F.5.1.2 LEVEL 2 DCPP IMPORTANCE LIST REVIEW

A similar review was performed on the importance listings from the Level 2 results. In this case, a composite importance file based on the following release categories was developed to identify potential SAMAs:

- ST1 (Large Early)
- ST2 (Small Early)
- ST4 (Bypass with AFW)
- ST5 (ISLOCA)

This method was chosen to prevent high frequency-low consequence events (i.e., the “Intact” and “Late” release categories) from biasing the importance listing. These four release categories included in the review account for over 98 percent of the dose-risk while accounting for only about 39 percent of the Level 2 frequency. Exclusion of the other results from the Level 2 review allows the contributors that are most important to dose-risk and cost-risk to rise to the top of the importance list.

Further grouping of the release categories was required given that the ST2 and ST4 release frequencies are about an order of magnitude higher than the ST1 and ST5 release frequencies. Separate importance lists were developed for each of these two groups, which ensures that the prominent contributors for each release category are reviewed.

The Level 2 split fractions were also reviewed down to the 1.02 level. As described for the Level 1 RRW list, split fractions below the 1.04 threshold RRW value are not expected to yield cost beneficial SAMAs, but the review was expanded to incorporate available information.

Tables F.5-2a and F.5-2b document the disposition of each split fraction in the Level 2 RRW list with RRW values greater than 1.02.

F.5.1.3 INDUSTRY SAMA REVIEW

The SAMA identification process for DCPP is primarily based on the PRA importance listings, the IPE, and the IPEEE. In addition to these plant-specific sources, selected industry SAMA submittals were reviewed to identify any Phase II SAMAs that were determined to be potentially cost beneficial at other plants. These SAMAs were further analyzed and included in the DCPP SAMA list if they were considered to address potential risks not identified by the DCPP importance list review.

While many of the industry SAMAs reviewed are ultimately shown not to be cost beneficial, some are close contenders and a small number have been estimated to be cost beneficial at other plants. Use of the DCPP importance ranking should identify the types of changes that would most likely be cost beneficial for DCPP, but review of selected industry Phase II SAMAs may capture potentially important changes not identified for DCPP due to PRA modeling differences or SAMAs that represent alternate methods of addressing risk. Given this potential, it was considered prudent to include a review of selected industry Phase II SAMAs in the DCPP SAMA identification process.

Phase II SAMAs from the following United States nuclear power sites have been reviewed:

- Susquehanna (Reference 62)
- Shearon Harris (Reference 5)
- H.B. Robinson (Reference 4)
- Point Beach (Reference 15)
- Prairie Island (Reference 16)
- Wolf Creek (Reference 65)

One General Electric BWR and five Westinghouse PWR sites were chosen from available documentation to serve as the potential Phase 2 SAMA sources. Many of the industry Phase 2 SAMAs were already represented by other SAMAs in the DCPP list, were known not to impact important plant systems or be relevant to the DCPP design, or were judged not to have the potential to be close contenders for DCPP. As a result, they were not added to the DCPP SAMA list. If there were any unique SAMAs that were considered to have the potential to be cost effective for DCPP, they were added to the list. The cost effective SAMAs for each of the sites identified above are reviewed in the following subsections.

F.5.1.3.1 Susquehanna Steam Electric Station

Review of SSES Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for DCPP	Disposition for DCPP SAMA List
2a	Improve Cross-Tie Capability Between 4kV AC Emergency Buses (A-D, B-C)	SSES did not credit cross-tie between EDG trains and relied on the swing EDG to mitigate EDG failures. Cross-tie from the opposite unit is available at DCPP, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).	Already included
6	Procure Spare 480V AC Portable Station Generator	This SAMA was developed to address the hardware failure contribution from their existing portable 480V generator. A form of the portable generator SAMA is included on the DCPP list (SAMA 5), but the SAMA is expanded to meet the site specific needs for SBO mitigation.	Already included
2b	Improve Cross-Tie Capability Between 4kV AC Emergency Buses (A-BC-D)	This SAMA is an enhancement over SSES SAMA 2a and allows cross-tie between any EDG division. See explanation provided above for SAMA 2a.	Already included
3	Proceduralize Staggered RPV Depressurization When Fire Protection System Injection is the Only Available Makeup Source	This SAMA is specific to the SSES site and is based on the need to split flow from a single injection system between units. It is not applicable to the DCPP design.	Not required for the SAMA list
5	Auto Align 480V AC Portable Station Generator	This SAMA was designed for a plant that already had a portable generator, but the impacts of auto generator alignment can be considered for Diablo Canyon. In this case, auto alignment would primarily be important to ensure power could be available for RCP seal injection before the window that is set for seal cooling restoration.	Already included

F.5.1.3.2 Shearon Harris

Review of Shearon Harris Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for DCPP	Disposition for DCPP SAMA List
9	Proceduralize Actions to Open EDG Room Doors on Loss of HVAC and Implement Portable Fans	The EDG room HVAC was not a contributor to plant risk in the DCPP PRA importance list review but the PRA review did analyze the Switchgear Room HVAC (SAMA 8).	Already included
6	Flood Mitigation for Scenarios 6 and 7	This is a plant specific internal flooding issue related to valve qualification in flooding conditions. The internal events model includes internal flooding contributors, but no issues related to valve qualification or performance were identified in the importance list review for DCPP.	Not required for the SAMA list
8	Alternate Seal Cooling and Direct Feed to Transformer 1B3-SB	This SAMA was developed to address loss of 4kV bus events where power is available to the opposite 4kV bus, but vital equipment has failed on the powered bus. Loss of bus events are not important for DCPP.	Not required for the SAMA list

F.5.1.3.3 H.B. Robinson

The H.B. Robinson SAMA analysis used a generic SAMA list as its starting point and few plant specific insights were available that might pertain specifically to Westinghouse PWRs. One of the SAMAs included in the Phase 2 list was, however, related to an important issue at DCPP, which is discussed below.

Review of H.B. Robinson Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for DCPP	Disposition for DCPP SAMA List
Phase 2 SAMA 8	Create automatic swap over to recirculation on RWT depletion	The swap to recirculation mode is a prominent operator action for most PWRs but automating the process will further improve reliability and reduce the contribution of this action to core damage scenarios. The Phase 1 SAMA list includes this automatic swap to recirculation.	Already included

F.5.1.3.4 Point Beach

As with H.B. Robinson, this analysis relied on a generic SAMA list and few plant specific insights were available that might pertain specifically to Westinghouse PWRs. The SAMAs identified in the Point Beach submittal as potentially cost effective appeared to be procedural updates to include checkoff provisions within the procedures. Some HRA methodologies credit placekeeping aids in procedures as a means of reducing the potential to skip a step in the cognitive portion of the HEP. While inclusion of such provisions is reflected quantitatively in the PRA, it would be difficult to justify changes to a large number of procedures based on a detail in a specific HRA methodology. This type of SAMA was not included in the DCPP SAMA list.

F.5.1.3.5 Prairie Island Nuclear Generating Plant

Review of Prairie Island Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for DCPP	Disposition for DCPP SAMA List
9	Analyze Room Heat-up for Natural/Forced Circulation (Screenhouse Ventilation)	This SAMA was developed to support the use of alternate room cooling in the plant's screenhouse when normal cooling fails. The DCPP SAMA list includes a SAMA to install an additional train to the Switchgear Room HVAC (SAMA 8).	Already included
22	Provide Compressed Air Backup for Instrument Air to Containment	The instrument air system is modeled for DCPP, and the importance review identified the event to provide backup N2 bottles to pressurize the instrument air header (SAMA 9).	Already included

F.5.1.3.6 Wolf Creek Generating Station

Review of Wolf Creek Generating Station Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for DCPP	Disposition for DCPP SAMA List
2	Modify the Controls and Operating Procedures for Sharpe Station to Allow for Rapid Response	This is a site specific SAMA that was developed to allow the Wolf Creek operators to control a local diesel generating station from the Wolf Creek main control room. This SAMA is not applicable to DCPP.	Not required for the SAMA list
4 (case 2)	Update emergency procedures to direct local, manual closure of the RHR EJHV8809A and EJHV8809B valves if they fail to close remotely	This SAMA was developed to address questions about the ability of MOVs to close against the differential pressure in a specific ISLOCA sequence for Wolf Creek. This SAMA is not applicable to DCPP.	Not required for the SAMA list
5	Enhance procedures to direct operators to open EDG Room doors for alternate room cooling	The EDG room HVAC was not a contributor to plant risk in the DCPP PRA importance list review but the PRA review did analyze the Switchgear Room HVAC (SAMA 8).	Already included
1	Permanent, Dedicated Generator for the NCP with Local Operation of TD AFW After 125V Battery Depletion	This was designed to assist in an SBO that included a seal LOCA. The design includes a 4kV, 500kW EDG to power a charging pump and transformer to support the 125V battery chargers. This type of change, modified to meet the needs of DCPP, was identified as part of the PRA importance list review (SAMA 5).	Already included
3	AC Cross-tie Capability	This SAMA is designed to improve AC crosstie capability. Cross-tie from the opposite unit is available at DCPP, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).	Already included

Review of Wolf Creek Generating Station Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for DCPP	Disposition for DCPP SAMA List
13	Alternate Fuel Oil Tank with Gravity Feed Capability	For Wolf Creek, fuel oil failures contributed significantly to the CDF and an alternate method to transfer fuel to the EDG day tank was determined to be cost effective. The failure of the diesel fuel oil system is not considered a large contributor to plant risk at DCPP.	Not required for the SAMA list
14	Permanent, Dedicated Generator for the NCP, one Motor Driven AFW Pump, and a Battery Charger	This was designed to assist in an SBO that included a seal LOCA. The design includes a 4kV, 500kW EDG to power a charging pump, an AFW pump, and a transformer to support the 125V battery chargers. This type of change, modified to meet the needs of DCPP, was identified as part of the PRA importance list review (SAMA 5).	Already included

F.5.1.3.7 Industry SAMA Identification Summary

The important issues for DCPP are generally considered to be addressed by the SAMAs developed through the PRA importance list review. The plant changes suggested as part of that review were developed to meet the specific needs of the plant such that those SAMAs are more likely to provide effective means of risk reduction than SAMAs taken from other sites. However, effort was made to review other industry SAMA analyses to determine if other sites identified plant changes that could be cost beneficial for DCPP based on modeling differences or other factors. For DCPP, no additional SAMA candidates were identified based on a review of selected industry analyses.

F.5.1.4 DCPP IPE PLANT IMPROVEMENT REVIEW

The DCPP IPE generated a list of risk-based insights and potential plant improvements. Typically, changes identified in the IPE process are implemented and closed out; however, there are some items that are not completed within the industry due to high projected costs or other criteria. Because the criteria for implementation of a SAMA may be different than what was used in the post-IPE decision-making process, these recommended improvements are re-examined in this analysis.

As a result of the IPE review, several potential/completed improvements were identified for consideration. These types of changes do not directly impact plant risk, but they can be used to aid in the management of plant risk and are considered as potential SAMAs. The following table summarizes the status of these improvements:

Status of IPE Plant Enhancements

Description of Potential Enhancement	Status of Implementation	Disposition
Recirculation lines were added to the diesel generator day tank system in order to allow the system to operate continuously once a start demand was received. Also, provisions were made to allow for manual operation of the level control valves on the diesel generator day tanks and to allow a portable engine-driven pump to be connected to the system.	Implemented	No further review required.
For scenarios involving a complete loss of component cooling water, provisions have been made and procedures are in place to allow the use of fire water to cool the centrifugal charging pumps. This design feature allows reactor coolant pump seal injection and consequently reactor coolant pump seal cooling to be maintained for scenarios involving a complete loss of component cooling water.	Implemented	No further review required.
For seismic events that result in a loss of offsite power due to switchyard equipment failures, spare parts are stored on-site to allow expeditious recovery. This ensures that the parts will be available in a timely manner for use by recovery personnel.	Implemented	No further review required.

Status of IPE Plant Enhancements

Description of Potential Enhancement	Status of Implementation	Disposition
The 4.16 kV overcurrent relays actuate and trip the breakers to the 4.16 kV vital buses. To facilitate recovery, it was proposed that the seal-in contacts be removed to allow the overcurrent trip to be reset from the control room.	Not Implemented	Upon further investigation, it was determined that the existing capability and procedures to reset these relays from the control room were sufficient; therefore, the proposed modification was not implemented.
This modification consisted of replacing three-position valve control switches (with spring return to neutral) with two-position valve control switches (with maintained contacts).	Implemented	The change affects component cooling water pump discharge valves and safety injection pump suction valves. The new switches prevent valve position changes due to relay chatter.
Adding a sixth emergency diesel generator.	Implemented	Completed in 1993. No further review required.

All of the plant changes suggested in the IPE have been implemented at DCPP or were considered to be insufficient and therefore no further review of these items is required.

F.5.1.5 DCPP IPEEE PLANT IMPROVEMENT REVIEW

Similar to the IPE, any proposed plant changes that were previously rejected based on non-SAMA criteria should be re-examined as part of this analysis. In addition, any issues that are in the process of being resolved should be examined because their resolutions could be important to the disposition of some SAMAs. The IPEEE was used to identify these items.

The following table summarizes the status of the potential plant enhancements resulting from the IPEEE processes and its treatment in the SAMA analysis.

Status of IPEEE Plant Enhancements

DESCRIPTION OF POTENTIAL ENHANCEMENT	STATUS OF IMPLEMENTATION	DISPOSITION
A procedure modification is being evaluated. The control room evacuation procedure (OP AP-8A, Rev. 5) modification would require the reactor coolant pumps to be tripped in the event the control room fire is located in cabinets that could result in loss of CCW or auxiliary saltwater (ASW) systems.	Implemented	No further review required.

The above plant change suggested in the IPEEE is considered to have been implemented and no further review is required.

F.5.1.6 POST IPEEE SITE CHANGES

In addition to performing a review of the IPEEE results, it was necessary to review the changes to the site and surrounding area that were implemented after the completion of the IPEEE to determine if the changes could impact the conclusions of the external events analyses. The DCPP staff identified the procedural change to trip the RCPs on evacuation of the control room as the only major change since the submittal of the IPEEE. This change was documented in the IPEEE as a task that would be completed in the near future (see previous section for further details). Therefore no further discussion of DCPP post IPEEE site changes is necessary.

F.5.1.7 "OTHER" EXTERNAL EVENTS IN THE DCPP SAMA ANALYSIS

As identified in Section F.2, DCPP has quantifiable PRA models for both seismic and internal fire contributors. The results of these models were used to identify SAMAs for DCPP using the same process used for the internal events contributors, which addresses part of the DCPP external events risk. In addition to seismic and internal fire events, the IPEEE analyzed the risk posed by multiple other events. Of those that were relevant to the plant, only a subset was considered to have the potential to credibly impact plant operations. These event types, which were analyzed in the IPEEE, include the following:

- High Wind
- Ship Impact
- Accidental Aircraft Impact
- External Flooding
- Chemical Release
- External Fire

While it is possible that SAMAs could be developed to reduce the risk associated with these types of events, their low core damage frequencies imply that it is unlikely that any such SAMAs could be cost beneficial. This can be demonstrated by comparing the potential averted cost-risk (PACR) for each initiating event type with the minimum expected SAMA implementation cost of $100,000 for the site.

The review process is a multi-step evaluation. The first step is to develop a PACR for each of the external events contributors. The PACR represents the cost-risk that could be averted if all risk associated with a given initiating event could be eliminated (similar to a MACR, but for a specific initiating event). For example, the PACR for ship impact at the intake structure is assumed to be the external events component of the site MACR multiplied by the ratio of the site ship impact CDF to the site external events CDF: $14,800,000 * 3.80E-08 / 1.08E-04 = $5,207

Once the PACRs are developed for the initiating event categories, they can be compared to the minimum SAMA implementation cost for the DCPP site ($100,000, from Section F.5.1.1). If the PACR is less than the minimum SAMA implementation cost, then no SAMAs designed to specifically address the corresponding external event type would be cost beneficial and the event type can be screened from further consideration.

In order to develop the PACRs for DCPP, it has been assumed that the external events CDF is directly proportional to the MACR. It is recognized that the public impact of a core damage event varies depending on the scenario, but because there are no Level 2 or Level 3 results for the external events contributors, an alternate method of estimating the PACRs is required.

The following table summarizes the PACRs that were developed using the above process for each of the relevant external event contributors for which a CDF was developed (excluding fire and seismic events). The CDFs for the contributors that were considered to be negligible in the IPEEE (external fires, nearby facility accidents, etc.) are assumed to be smaller than the lowest quantified contributor (ship impact on intake structure). Given that the "ship impact" PACR is about $5,000, no potentially cost beneficial SAMAs are considered to exist for those external event contributors.

Review of External Events Screened in the DCPP IPEEE

Initiating Event Group	Estimated CDF (per yr, site)	PACR (site)	Disposition
High Winds	6.40E-07[1]	$87,704	The PACR is below the minimum expected cost of implementation for a SAMA. Screened from further review.
Ship Impact on Intake Structure	3.80E-08	$5,207	The PACR is below the minimum expected cost of implementation for a SAMA. Screened from further review.
Accidental Aircraft Impact	1.40E-06	$191,852	No potentially cost beneficial SAMAs identified.
External Flooding	1.44E-06[2]	$197,333	The IPEEE CDF does not account for the availability of the new self cooled CCP, which would be available in loss of ASW events. No SAMAs are considered to be required.
Hazardous Chemical Release	1.60E-06[3]	$219,259	The only contributor for this initiating event was an ammonium hydroxide spill, but ethanolamine has replaced ammonium hydroxide at the site. The CDF for this type of event at DCPP is, therefore, considered to be negligible and no SAMAs are required.

[1] This is not a CDF, but an annual exceedance frequency for winds of 200 mph or greater. The IPEEE did not develop a conditional core damage frequency for a high wind event, but the actual CDF would be less than the exceedance frequency.
[2] This frequency does not account for the installation of the self cooled CCP, which would be available in loss of ASW scenarios.
[3].The IPEEE hazardous material release risk was based on a spill of ammonium hydroxide; other chemical stored on-site were determined not to pose a risk to the MCR operators. Since the IPEEE was completed, the ammonium hydroxide was replaced by the chemical ethanolamine, which was also determined not to pose a risk to MCR operators.

The IPEEE was published prior to September 11, 2001. Since that time, there have been efforts to address intentional aircraft impacts and other sabotage events in other forums. For example, security orders issued to licensees following the events of September 11, 2001 required licensees to implement certain mitigation strategies. Under section B.5.b, DCPP implemented mitigation measures to generally deal with the situation in which large areas of the plant were lost due to fires and explosions, whatever the beyond-design basis initiator and without regard to cost. Accordingly, even though the intentional aircraft attacks and sabotage-related events are outside the scope of the SAMA analysis, the site has already taken steps to mitigate severe accidents that might result from such initiators.

Moreover, the NRC has already included a sabotage/terrorism assessment in the license renewal GEIS (NUREG-1437), Chapter 5. The NRC concludes (at 5-18) that ". . . if such events were to occur, the Commission would expect that resultant core damage and radiological releases would be no worse than those expected from internally initiated events."

Based on the fact that this topic is currently being analyzed in another forum, the NRC's expectation that severe accidents initiated by a terrorist attack can be correlated to other internally initiated events, and given an inherent inability to quantify the probability of hypothetical aircraft impacts and other terrorist-initiated events, intentional aircraft impacts and other terrorist-initiated events are not considered further in the DCPP SAMA analysis.

With regard to accidental aircraft impact, the PACR is estimated to be larger than the minimum expected SAMA implementation cost of $100,000, but only by about $92,000. This difference is small and the scope of potential SAMAs that could potentially be cost beneficial would still likely be limited to procedure improvements. No procedure improvements specifically related to reducing the risk of an accidental aircraft strike have been identified.

The IPEEE external flooding CDF also correlates to a PACR that exceeds the minimum expected SAMA implementation cost of $100,000; however, that CDF does not reflect the capabilities of the newly installed, self cooled CCP. The IPEEE depended on crediting actions to align fire water to the original CCPs to support pump lube oil cooling so that RCP seal cooling could be maintained in loss of ASW scenarios (i.e., external flooding events). For the current plant configuration, the self cooled CCP would be available to maintain RCP seal cooling without operator intervention. Even if removing the requirement to align fire water to the CCPs only reduced the external flooding CDF by a factor of 2, the PACR would be $98,667, which is below the minimum expected SAMA implementation cost. No SAMAs are required for this contributor.

The hazardous chemical release contribution in the IPEEE was based on a spill of ammonium hydroxide from one of the several tanks located on-site. Since the completion of the IPEEE, ammonium hydroxide has been replaced by the chemical ethanolamine. The IPEEE indicates that ethanolamine was being evaluated as a candidate to replace ammonium hydroxide at the time of the analysis and that ethanolamine posed no risk to the MCR operators. Based on the removal of the only chemical identified as a potential risk to MCR operators, the hazardous chemical release CDF for the currently plant configuration is considered to be negligible and no SAMAs are required to address this type of event.

In summary, no SAMAs have been developed to specifically address the risk related to the "other" external events contributors at DCPP.

F.5.2 PHASE 1 SCREENING PROCESS

The initial list of SAMA candidates is presented in Table F.5-3. The process used to develop the initial list is described in Section F.5.1.

The purpose of the Phase 1 analysis is to use high-level knowledge of the plant and SAMAs to preclude the need to perform detailed cost-benefit analyses on them. The following screening criteria were used:

- Applicability to the Plant: If a proposed SAMA does not apply to the DCPP design, it is not retained. Similarly, any SAMAs that have already been implemented by PG&E or achieve results that PG&E has achieved by other means can be screened as they are not applicable to the current plant design.

The use of these criteria is not often explicitly used in the Phase I analysis because the SAMA methodology generally precludes inclusion of such SAMAs; however, they are listed as a possible screening method given that there may be circumstances in which a SAMA would be included in the list even if it is not relevant to the site. An example may be the inclusion of a high profile SAMA that is well known in the industry, but not applicable to the specific site design. Such a SAMA may be included for documentation purposes. Another example may be an unimplemented SAMA from the IPE that has been superseded by another plant enhancement.

- Implementation Cost Greater than Screening Cost: If the estimated cost of implementation is greater than the modified MACR (refer to Section F.4.6), the SAMA cannot be cost beneficial and is screened from further analysis.

Table F.5-3 provides a description of how each SAMA was dispositioned in Phase 1. Those SAMAs that required a more detailed cost-benefit analysis are passed to the Phase 2 analysis and evaluated in Section F.6. Table F.6-1 contains the Phase 2 SAMAs.

F.6 PHASE 2 SAMA ANALYSIS

The SAMA candidates identified as part of the Phase 2 analysis are listed in Table F.6-1. The base PRA model was manipulated to simulate implementation of each of the proposed SAMAs and then quantified to determine the risk benefit. Truncation values and binning cutoffs are the same as used in the base PRA model (CDF, LERF, Seismic and Fire), including Level 2 endstates.

In general, in order to maximize the potential risk benefit due to implementation of each of the SAMAs, the failure probabilities assigned to new basic events, such as HEPs, were optimistically chosen so as not to inadvertently screen out any potential cost-beneficial SAMAs. Also, any new model logic that was added to the PRA model in order to simulate SAMA implementation was also simplified and optimistically configured to achieve the same effect.

Determination of the cost-risk benefit for each of the Phase 2 SAMAs involved calculating what was known as the averted cost-risk, which was obtained by comparing the SAMA results with the base case MMACR value. This value is then compared with the cost of implementation to determine the overall net benefit. That is, the net value is determined by the following equation:

Net Value = (baseline cost-risk of plant operation (MMACR) – cost-risk of plant operation with SAMA implemented) – cost of implementation

If the net value of the SAMA is negative, the cost of implementation is larger than the benefit associated with the SAMA and the SAMA is not considered cost beneficial. The baseline cost-risk of plant operation was derived using the methodology presented in Section F.4. The cost-risk of plant operation with the SAMA implemented is determined in the same manner with the exception that the revised PRA results reflect implementation of the SAMA.

The implementation costs used in the Phase 1 and 2 analyses consist of DCPP specific estimates developed by plant personnel. It should be noted that DCPP specific implementation costs do include contingency costs for unforeseen difficulties, but do not account for any replacement power costs that may be incurred due to consequential shutdown time. Table F.5-3 provides implementation costs for each Phase 1 and Phase 2 SAMA.

The following sections describe the simplified cost-benefit analysis that was used for each of the Phase 2 SAMA candidates. It should be noted that the sum of the release category frequencies for the base SAMA case (8.44E-06 /yr) was chosen as the base CDF value against which all other modeled SAMAs were compared instead of the nominal Level 1 CDF value of 8.47E-06. This was due to the fact that all of the estimated MMACR results for each of the modeled SAMAs were based on summing all of the individual release category frequencies from the PRA cases. Therefore, this approach was viewed as more appropriate in obtaining the averted cost risk for each of the SAMAs. Furthermore, the release category results provided for each SAMA do not include contributions from the negligible release category.

It should be noted that DCPP units 1 and 2 are essentially identical in design and operation (see Section F.2.1 for further discussion). Such differences that do exist are not believed to be significant from a risk perspective. As such, the site PRA model (DC01A), which references Unit 1 and common components, was employed to evaluate each of the risk benefits and averted costs for each of the SAMAs, and was viewed as also being applicable to Unit 2. That is, if a particular SAMA proves cost beneficial for Unit 1, it will likewise be cost beneficial for Unit 2.

F.6.1 SAMA 2: AUTOMATE SWAP TO RECIRCULATION

The operators are well trained on the action to transition the RCS injection systems to recirculation mode, but automating the process will further improve reliability and reduce the contribution of this action to core damage scenarios.

This SAMA makes the switchover to the containment sump automatic where sump level indication, digital logic, and signal wiring to various 480V valves comprise the hardware changes, and the human action is no longer necessary.

Assumptions:

Assume the hardware failure rate is similar to 2 trains of SSPS (see split fraction S12) and is approximately 5.0E-4. The resultant split fraction will then be the sum of sump plug screening probability (see basic events RFBKA1, RFBKA3, and RFBKA4), and failure probability of 2 SSPS trains.

PRA Model Changes to Model SAMA:

Split Fractions: RF3, OR1, RF1, RF4

Top Event: RF

RF3 models the operator failing to switchover to the containment sump after a large or medium LOCA (see MLOCA and LLOCA event trees); RF1 models the switchover after a small LOCA; and RF4 models it after core damage has occurred. The other RF split fractions have little or no fractional importance to CDF. The model for RF also includes sump screen plugging at various probabilities depending on the type of LOCA.

Model Change(s):

RF1= 5.0E-04 + 1.49E-04 = 6.49E-04

RF3 = 5.0E-04 + 8.07E-04 = 1.31E-03

RF4= 5.0E-04 + 4.84E-02 = 4.89E-03

RFF= unaffected (this is assigned when the RHR pumps are failed)

Results of SAMA Quantification:

Implementation of this SAMA yields a moderate reduction in the internal CDF and Dose-Risk, and only a slight reduction in Offsite Economic Cost-Risk. There were no changes in either fire or seismic CDF. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	7.16E-06	8.32	$33,213	1.39E-05	3.77E-05
Percent Change	15.1	5.4	1.4	0.0	0.0

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
$\text{Frequency}_{\text{BASE}}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$\text{Frequency}_{\text{SAMA}}$	4.63E-08	1.65E-06	2.78E-06	1.23E-06	2.88E-07	1.16E-06	**7.16E-06**
$\text{Dose-Risk}_{\text{BASE}}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
$\text{Dose-Risk}_{\text{SAMA}}$	0.76	2.98	0.09	1.55	2.93	0.01	**8.32**
$\text{OECR}_{\text{BASE}}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
$\text{OECR}_{\text{SAMA}}$	$778	$11,868	$25	$8,343	$12,198	$1	**$33,213**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 2 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$7,323,859	$76,141

Based on a $6,509,256 cost of implementation for DCPP, the net value for this SAMA is -$6,433,115 ($76,141 - $6,509,256), which results in this SAMA <u>not</u> being cost beneficial.

F.6.2 SAMA 3: ALTERNATE DC GENERATOR

In order to mitigate DC system failures, an alternate DC generator could be used to directly power a bus (bypasses charger faults) or directly power critical loads (bypasses distribution failures). The generator should be stored in a seismically qualified area so that it would potentially be available to respond in seismic scenarios.

Assumptions:

It is assumed that the sum of top events DA and DB, conservatively rounded up to 5.0E-4, would equal the failure probability of aligning a backup DC source when all normal DC sources have failed.

PRA Model Changes to Model SAMA:

Split Fractions: REBAT (1.00E-01), DF1, DG3, etc.

Top Event: RE, DF and DG

REBAT models the probability of restoring a vital DC bus (DF, DG or DH) given that offsite power and vital AC buses remain available. The probability is a screening value. This SAMA proposes a seismically qualified stand-alone DC power source. REBAT is only credited for simple plant trips (defined by macro SIMPTRIP), such as reactor trip, turbine trip, loss of feedwater, loss of condenser vacuum, etc. There is no credit applied for fire or seismic initiators.

In top event DB there is a human action DBHUMFA which models aligning a backup charger for non-seismic events, whose probability is 2.60E-4. This human action can be used as a surrogate for aligning a backup DC source. Top event DA models the DC buses where split fraction DA1F is the failure probability for a single DC bus including maintenance. DA1F is equal to 7.86E-5.

Model Change(s):

REBAT = 5.0E-04.

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. Fire CDF was reduced dramatically, while seismic CDF remained unchanged. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	7.56E-06	7.46	$28,618	4.40E-06	3.77E-05
Percent Change	10.4	15.2	15.1	68.3	0.0

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
Frequency_{BASE}	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
Frequency_{SAMA}	6.64E-08	9.98E-07	3.78E-06	1.21E-06	2.86E-07	1.22E-06	**7.56E-06**
Dose-Risk_{BASE}	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
Dose-Risk_{SAMA}	1.09	1.80	0.13	1.52	2.91	0.01	**7.46**
OECR_{BASE}	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
OECR_{SAMA}	$1,116	$7,166	$33	$8,188	$12,114	$1	**$28,618**

The Unit 1 cost risk associated with the Fire CDF reduction is $522,962. This value is the product of the SAMA-to-Base Fire CDF ratio (4.40E-06 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $1,124,446.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 3 Net Value			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
DCPP Unit 1	$7,400,000	$6,092,343	$1,307,657

Based on a $5,863,176 cost of implementation for DCPP, the net value for this SAMA is -$4,555,519 ($1,307,657 - $5,863,176), which results in this SAMA not being cost beneficial.

F.6.3 SAMA 5: USE AN ALTERNATE EDG TO SUPPORT LONG TERM AFW OPERATION AND A 480V AC SELF-COOLED PDP FOR PRIMARY SIDE MAKEUP

A potential SBO mitigation strategy is to use a small, alternate EDG to power a station battery charger for level instrumentation and AFW control. In addition, if power can be supplied to a 480V AC self-cooled positive displacement pump, primary makeup could be maintained to mitigate a seal LOCA. This SAMA is geared towards mitigating the higher probability (low leakrate) RCP seal LOCA (21 gpm per pump, 84 gpm total), which accounts for 78 percent of all seal LOCAs.

Assumptions:

The availability of an independent source of control and instrument power would alter the value of some of the AW top event split fractions. Specifically those split fractions that represent failure of support to the turbine driven AFW pump would now revert back to their base value. In general that base value is approximately 1.0E-02 lower than the original value below.

Top event CH models cold leg injection via the CCPs. Because this SAMA provides a redundant injection pump from a separate stand-alone AC power source, each split fraction in the GENTRAN event tree can be reduced by the failure rate of such a system. The assumed failure rate is 1.0E-02. The guaranteed failed split fraction (CHF) is no longer 1.0E+00, but defaults to the failure rate of the stand-alone redundant train, 1.0E-02.

The case where top event TD fails because of the failure of the stand-alone power train as the only remaining control power source is ignored. In this instance split fraction CHF would need a new rule and would be assigned 1.00E+00.

<u>PRA Model Changes to Model SAMA:</u>

Split Fractions: GF1, GG2, GH3, OG1, OGA1, OGAX, DGC1

Top Events: OG, OGA, and DGC

Top Event: TD, CH

These split fractions represent loss of AC power. This SAMA represents installing a seismically robust, stand alone 480V AC power source that could provide power to the AFW level instrumentation as well as powering an additional high pressure injection (positive displacement) pump for RCS inventory control.

Model Change(s):

Top Event AW Model Changes			
Split Fraction	**Original Value**	**New Value**	**Description**
AW7	5.27E-03	5.27E-05	SUPPORT FOR ALL 10 PERCENT STM DMPS AND THE TDP UNAVAILABLE
AW7B	5.27E-03	5.27E-05	SAME AS AW7 - STEAM LINE BREAKS
AW7L	6.10E-03	6.10E-05	SAME AS AW7 - RCP'S TRIPPED AND NATURAL CIRCULATION MODE
AWAA	7.24E-02	7.24E-04	NO SUPPORT FOR 10PERCENT STM DMPS/TDP/MDP 1-2
AWAAB	7.24E-02	7.24E-04	SAME AS AWAA - STEAM LINE BREAKS
AWAAL	7.32E-02	7.32E-04	SAME AS AWAA - RCP'S TRIPPED AND NATURAL CIRCULATION MODE
AWAB	7.24E-02	7.24E-04	NO SUPPORT FOR 10 PERCENT STM DMPS/TDP/MDP 1-3
AWABB	7.24E-02	7.24E-04	SAME AS AWAB - STEAM LINE BREAKS
AWABL	7.32E-02	7.32E-04	SAME AS AWAB - RCP'S TRIPPED AND NATURAL CIRCULATION MODE
AWD	1.06E-04	1.06E-06	SUPPORT FOR THE TDP UNAVAILABLE
AWDB	1.06E-04	1.06E-06	SAME AS AWD - STEAM LINE BREAKS
AWDL	9.39E-04	9.39E-06	SAME AS AWD - RCP'S TRIPPED AND NATURAL CIRCULATION MODE

Top Event CH Model Changes		
Split Fraction	**Old Value**	**New Value**
CH1	6.63E-04	6.63E-06
CH1A	7.48E-03	7.48E-05
CH1B	7.48E-03	7.48E-05
CH2	1.52E-02	1.52E-04
CH3	1.52E-02	1.52E-04
CH4	8.47E-03	8.47E-05
CH4A	1.52E-02	1.52E-04
CH5	8.47E-03	8.47E-05
CH5A	1.52E-02	1.52E-04
CH6	7.46E-04	7.46E-06
CH6A	8.03E-03	8.03E-05
CH6B	8.03E-03	8.03E-05
CH7	1.58E-02	1.58E-04
CH8	1.58E-02	1.58E-04
CH9	8.56E-03	8.56E-05
CH9A	1.58E-02	1.58E-04
CHA	8.56E-03	8.56E-05
CHAA	1.58E-02	1.58E-04
CHF	1.00E+00	1.00E-02

Results of SAMA Quantification:

Implementation of this SAMA yielded an appreciable reduction in internal CDF and nominal reductions in Dose-Risk and Offsite Economic Cost-Risk. Fire CDF was reduced significantly, while a negligible reduction was observed with seismic CDF. The results are summarized in the following table:

SAMA 5 PRA Model Results

	CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	7.63E-06	8.52	$32,896	1.25E-05	3.72E-05
Percent Change	9.6	3.1	2.4	10.3	1.4

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

SAMA 5 Internal Events Results By Release Category

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
Frequency_{BASE}	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
Frequency_{SAMA}	6.63E-08	1.66E-06	3.50E-06	1.23E-06	2.72E-07	9.04E-07	**7.63E-06**
Dose-Risk_{BASE}	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
Dose-Risk_{SAMA}	1.09	2.98	0.12	1.55	2.78	0.00	**8.52**
OECR_{BASE}	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
OECR_{SAMA}	$1,113	$11,905	$31	$8,307	$11,539	$1	**$32,896**

The Unit 1 cost risk associated with the Fire CDF reduction is $1,476,889. This value is the product of the SAMA-to-Base Fire CDF ratio (1.25E-05 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $170,519. Calculated in a similar manner, Seismic CDF averted cost risk is $61,641.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 5 Net Value			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
DCPP Unit 1	$7,400,000	$7,111,432	$288,568

Based on a $6,441,418 cost of implementation for DCPP, the net value for this SAMA is -$6,152,850 ($288,568 - $6,441,418), which results in this SAMA not being cost beneficial.

F.6.4 SAMA 7: REPLACE OR MODIFY THE BATTERY CHARGERS TO OPERATE WITHOUT THE BATTERIES

Typically, battery chargers are not designed to support all DC demands without the batteries. If they can be replaced or modified so that they could do this, it would mitigate battery failure scenarios.

Assumptions:

This SAMA postulates the replacement of the chargers by ones sized such that there is no dependency on the successful operation of the battery. To evaluate this scenario the model can then be changed by removing the dependency of the 125V DC busses on the associated battery.

Note: this underestimates the risk benefit because some ELECPWR event tree macro rules should be changed to get the full effect.

PRA Model Changes to Model SAMA:

Split Fraction: D2F1, D2G2, DA3FGH, DB2H, D2G1, etc.

Top Event: DF, DG, DH

In the vital DC power model the batteries are model in D2F, D2G and D2H. The 125V DC buses and chargers are modeled in top events DF, DG and DH respectively. If a DC battery fails, then the associated 125V DC bus is failed.

Model Change(s):

Split Fraction	Old Rule	New Rule
DFF	~~D2F=F~~+(A8F=F*A8H=F)	A8F=F*A8H=F
DGF	~~D2G=F~~+(A8G=F*A8H=F)	A8G=F*A8H=F
DHG	~~D2H=F~~+(A8F=F*A8H=F)	A8F=F*A8H=F

Results of SAMA Quantification:

Implementation of this SAMA yielded a nominal reduction in the CDF, and negligible changes in Dose-Risk and Offsite Economic Cost-Risk. Fire CDF and seismic CDF both remained unchanged. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.10E-06	8.81	$33,946	1.39E-05	3.77E-05
Percent Change	4.0	-0.2	-0.7	0.0	0.0

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
$Frequency_{BASE}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$Frequency_{SAMA}$	6.90E-08	1.71E-06	3.74E-06	1.23E-06	2.87E-07	1.06E-06	**8.10E-06**
$Dose\text{-}Risk_{BASE}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
$Dose\text{-}Risk_{SAMA}$	1.13	3.07	0.13	1.55	2.93	0.01	**8.81**
$OECR_{BASE}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
$OECR_{SAMA}$	$1,159	$12,250	$33	$8,320	$12,185	$1	**$33,946**

At times, the SAMA quantification will alter the way events are distributed in the Level 2 bins such that sequences that used to be classified as one type of release are reclassified as another. The above tables illustrate this point where dose-risk and OECR were observed to increase (ST2 and total) while internal CDF decreased. This is an anomaly of the Level 2 model quantification and is considered to have negligible impact on the overall results.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 7 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$7,392,179	$7,821

Based on a $2,552,563 cost of implementation for DCPP, the net value for this SAMA is -$2,544,742 ($7,821 - $2,552,563), which results in this SAMA not being cost beneficial.

F.6.5 SAMA 8: INSTALL AN ADDITIONAL TRAIN OF SWITCHGEAR ROOM HVAC

Alternate Switchgear Room cooling procedures already exist for DCPP, but the loss of room cooling is still an important issue. While costly, a potential means of reducing the HVAC failure contribution would be to install an independent train of HVAC.

Assumptions:

The probability of failure of a single train of HVAC is equal to ~ 1.00E-04 (see split fraction SV2). For non-LOSWV initiators, if the redundant train were in place the recovery modeled by RE6A should be replaced by the failure probability of a single train of HVAC in place of the second chance recovery action.

For the LOSWV initiator, top event RE will most frequently assign split fraction RE6. This split fraction is also set to human action ZHESV3 modeling a second nearly independent attempt at restoring ventilation. Thus for LOSWV initiators, split fraction RE6 should be replaced by the probability of failure of a single train of ventilation, or ~ 1.00E-04 (see split fraction SV2) in place of the human action.

<u>PRA Model Changes to Model SAMA:</u>

Split Fraction: RE6A, RE6, SV1, AH1, AA1H

Top Event: RE

480V switchgear ventilation is modeled as both an initiator (LOSWV) and a system (SV) that can fail given any other initiator. SAMA No. 8 considers the impact of making available a redundant train of ventilation to the 2 trains already available (supply and exhaust fans S/E-43 and S/E-44). Adding a redundant train could lower the initiating event frequency, the value of the split fractions in top event SV which models 480V switchgear ventilation, or the HVAC recovery split fractions found in top event RE.

Top event SV models the 480V switchgear ventilation system. Embedded at the top of the SV fault tree structure (used for all top event SV split fractions) is the operator action ZHESV3 (operator fails to open the doors to the inverter/battery room and select the backup power to the inverter). In other words nearly all the SV split fraction cutsets are multiplied by the ZHESV3 term (via basic event SVHE which is set equal to ZHESV3).

RE6A is the recovery split fraction used for non-LOSWV initiators where the 480V switchgear room ventilation is lost via top event SV. This split fraction models the human action to open the doors to the inverter/battery room and select the backup power to the inverter. It uses HEP ZHESV3 = 2.79E-03/0.01 to model the second attempt to restore ventilation.

The LOSWV initiator models the annual loss of the 480V switchgear room ventilation. Embedded at the top of the fault tree structure is the operator action ZHESV3 (operator fails to open the doors to the inverter/battery room and select the backup power to the inverter). In other words nearly all the initiator cutsets are multiplied by the ZHESV3 term (via basic event SVHE which is set equal to ZHESV3).

Model Change(s):

RE6A = 1.00E-04

RE6 = 1.00E-04

Results of SAMA Quantification:

Implementation of this SAMA yielded a nominal reduction in the internal CDF, Dose-Risk and Offsite Economic Cost-Risk. Fire CDF was reduced dramatically, while seismic CDF remained unchanged. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	7.54E-06	8.08	$31,142	4.40E-06	3.77E-05
Percent Change	10.6	8.1	7.6	68.4	0.0

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
$\text{Frequency}_{\text{BASE}}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$\text{Frequency}_{\text{SAMA}}$	6.70E-08	1.33E-06	3.51E-06	1.22E-06	2.87E-07	1.12E-06	**7.54E-06**
$\text{Dose-Risk}_{\text{BASE}}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
$\text{Dose-Risk}_{\text{SAMA}}$	1.10	2.40	0.12	1.54	2.92	0.01	**8.08**
$\text{OECR}_{\text{BASE}}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
$\text{OECR}_{\text{SAMA}}$	$1,125	$9,563	$31	$8,266	$12,156	$1	**$31,142**

The Unit 1 cost risk associated with the Fire CDF reduction is $526,613. This value is the product of the SAMA-to-Base Fire CDF ratio (4.40E-06 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $1,120,795.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 8 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$6,164,996	$1,235,004

Based on a $6,376,810 cost of implementation for DCPP, the net value for this SAMA is -$5,141,806 ($1,235,004 - $6,376,810), which results in this SAMA not being cost beneficial.

F.6.6 SAMA 9: BACKUP AIR SYSTEM FOR PORV PCV 474

Currently, loss of offsite power results in the loss of the IA system. Changing the air supply to PCV 474 (Pressurizer PORV) to a class I backup air supply would prevent this and reduce the loss of IA contributions to core damage.

Assumptions:

With the addition of a self-contained compressed air system (N2 bottles) that could support the PORV, top event OB split fractions used in the seismic general transient tree would change slightly given air would be available to PORV 474. The split fraction values are dominated by the seismic HEP to initiate feed and bleed at 3.30E-01, so the addition of a backup air supply dedicated to PORV 474 will have a nominal effect. With air support available to PORV 474, the OB seismic split fractions would be equal to the HEP (ZHEOB1).

For non-seismic initiating events, the feed and bleed HEP is 1.99E-02 and according to the split fraction cause table, dominates the split fraction values. If instrument air were available to PORV 474, then split fractions OB1 and OB2 would revert to the all support case. The guaranteed failure split fraction is unaffected because it is used when power to the other 2 PORVs is unavailable.

PRA Model Changes to Model SAMA:

Split Fraction: AWS4

Top Event: AW

Split fraction AWS4 is the intermediate split fraction for AW4S, the seismic split fraction for auxiliary feedwater where both motor-driven pumps are unavailable. This SAMA would provide a seismic resistant backup air supply to support feed and bleed operations as is necessary after the loss of all secondary side cooling. Top event IA supports the operation of PORV 474 and top event OB models operation of the 3 PORVs where success requires 2/3 to operate. In other words, success of OB is dependent on the success of IA for all 3 PORVs to remain available.

Model change(s):

Split Fraction	Original Value	New Value	Description
OB1S	3.42E-01	3.30E-01	Loss of Instrument Air, PORV 474 DISABLED - SEIS W/ESAM=30
OB2S	3.42E-01	3.30E-01	Loss of Instrument Air, Charging failed, PORV 474 DISABLED - SEIS W/ESAM=30
OB1	2.26E-02	1.18E-02	Loss of Instrument Air - PORV 474 DISABLED
OB2	2.26E-02	1.18E-02	Loss of Instrument Air, Charging failed - PORV 474 DISABLED
OB3	1.18E-02	Unchanged	ALL SUPPORT AVAILABLE
OBF	1.00E+00	Unchanged	Guaranteed Failure

Results of SAMA Quantification:

Implementation of this SAMA yielded a minor reduction in the internal CDF, and negligible reductions in Dose-Risk and Offsite Economic Cost-Risk. Similarly, Fire CDF was reduced marginally, while seismic CDF remained virtually unchanged. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.27E-06	8.75	$33,613	1.37E-05	3.75E-05
Percent Change	2.0	0.5	0.3	1.2	0.5

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
$Frequency_{BASE}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$Frequency_{SAMA}$	7.02E-08	1.66E-06	3.91E-06	1.23E-06	2.87E-07	1.12E-06	**8.27E-06**
Dose-$Risk_{BASE}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
Dose-$Risk_{SAMA}$	1.15	2.98	0.13	1.55	2.93	0.01	**8.75**
$OECR_{BASE}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
$OECR_{SAMA}$	$1,179	$11,898	$34	$8,317	$12,184	$1	**$33,613**

The Unit 1 cost risk associated with the Fire CDF reduction is $1,629,274. This value is the product of the SAMA-to-Base Fire CDF ratio (1.37E-05 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $18,134. Calculated in a similar manner, Seismic CDF averted cost risk is $19,599.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 9 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$7,348,812	$51,188

Based on a $1,692,730 cost of implementation for DCPP, the net value for this SAMA is -$1,641,542 ($51,188 - $1,692,730), which results in this SAMA not being cost beneficial.

F.6.7 SAMA 10: INSTALL HIGH TEMPERATURE RCP SEALS[1]

Mitigation strategies to supply alternate RCP seal cooling can reduce the risk of RCP seal LOCAs, but if high temperature seals designed to activate and seal off a stopped, overheated RCP shaft were installed, it would remove the need to perform the time critical actions associated with restoration of seal cooling after it is lost, especially during an SBO.

Assumptions:

This SAMA assumes the installation of high temperature RCP seals which are very unlikely to leak on loss of all seal cooling. Two assumptions are made: 1) with some sort of cooling supplied, either thermal barrier or seal injection, the seal failure rate is 1.0E-3, and 2) with no seal cooling at all the seal failure rate is 1.0E-2. The split fractions with the highest fractional importance are SEF, SE9, SE5F, SE4, SE3F and SE1. These split fractions will be changed to reflect new RCP seals.

The seal LOCA initiator is also affected and should be reduced, it is assumed, by a factor of 10 from 2.45E-3 to 2.45E-04.

PRA Model Changes to Model SAMA:

Split Fraction: RF1

Top Event: SE

The seal LOCA model is implemented via top event SE which models loss of thermal barrier cooling and seal injection. It also has basic events for the probability of seal failure in the first 10 minutes after loss of all seal cooling (0.22) as well as human

[1]The high temperature seals identified in SAMA 10 have not been installed in any commercial plants; furthermore, implementation would only be considered once the seals have been shown to be viable and the NRC has validated them as a means of eliminating RCP seal LOCAs (provided they are not thermally shocked, etc.).

actions to align fire water as an alternate source of water (ZHESE1 and ZHESE2 depending on whether it is a loss of all CCW scenario).

Model Change(s):

Change top event split fractions using the probabilities assumed above.

Split Fraction	Base Value	Assumed Value
SEF – no support, GF	1.00E+00	1.00E-02
SE9 – no seal cooling	2.20E-01	1.00E-02
SE5F – CCP 1-1 unavailable	1.32E-02	1.00E-03
SE4 – no support either CCP	4.14E-03	1.00E-03
SE3F – no CCW to CCP 1-1	1.27E-02	1.00E-03
SE1 – no CCW to either CCP	2.30E-03	1.00E-03
Change the seal LOCA initiator SELOCA from 2.45E-03 to 2.45E-04.		

Results of SAMA Quantification:

Implementation of this SAMA yields a nominal reduction in the CDF and lesser reductions in Dose-Risk and Offsite Economic Cost-Risk. Fire CDF was reduced dramatically, while seismic CDF was reduced about the same as internal CDF. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	7.30E-06	8.34	$32,320	3.11E-06	3.32E-05
Percent Change	13.5	5.2	4.1	77.6	12.0

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
Frequency_{BASE}	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
Frequency_{SAMA}	6.34E-08	1.54E-06	3.26E-06	1.20E-06	2.85E-07	9.56E-07	**7.30E-06**
Dose-Risk_{BASE}	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
Dose-Risk_{SAMA}	1.04	2.77	0.11	1.51	2.90	0.00	**8.34**
OECR_{BASE}	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
OECR_{SAMA}	$1,065	$11,035	$29	$8,116	$12,075	$1	**$32,320**

The Unit 1 cost risk associated with the Fire CDF reduction is $374,454. This value is the product of the SAMA-to-Base Fire CDF ratio (3.11E-06 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $1,124,446. Calculated in a similar manner, Seismic CDF averted cost risk is $535,463.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 10 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$5,502,105	$1,897,895

Based on a $6,234,672 cost of implementation for DCPP, the net value for this SAMA is -$4,336,777 ($1,897,895 - $6,234,672), which results in this SAMA not being cost beneficial.

F.6.8 SAMA 11: INSTALL CONTAINMENT COMBUSTIBLE GAS IGNITORS

Early containment failure is a large contributor to the LERF release category. Although inerting containment in accident conditions could help prevent burns of combustible gases, a better solution is to install battery-backed igniters throughout the upper dome of containment.

Assumptions:

The conditions in containment that result in the production of hydrogen is the result of high temperatures and damaged fuel cladding. As such, significant frontline systems are likely to be disabled. Hydrogen igniters with their own backup power supply would remain available to mitigate the buildup of hydrogen post-accident. It is assumed, therefore, the split fractions CECET1 and HECET1 are reduced by 1.0E-02, which is the failure probability of such a system.

PRA Model Changes to Model SAMA:

Split Fraction: CECET1, HECET1

Top Event: CECET, HECET

Top event CECET models the probability of containment failure following a hydrogen burn in containment (in event tree CET). The value for split fraction CECET1 is a phenomenon probability and not the result of a system failure. This SAMA would provide for hydrogen igniters with battery backup to mitigate the buildup of hydrogen after an accident.

Top event HECET models the likelihood of a hydrogen burn within 4 hours of vessel failure. If this SAMA were in place the likelihood of a burn within 4 hours of vessel failure becomes less likely.

Model Change(s):

Split Fraction	**Base Value**	**Assumed Value**
CECET1	2.28E-02	2.28E-04
HECET1	7.10E-01	7.10E-03
HECET2	7.10E-01	7.10E-03

Results of SAMA Quantification:

Implementation of this SAMA yields no reduction in the internal CDF, a nominal reduction in Dose-Risk and small reduction in Offsite Economic Cost-Risk. Fire CDF was reduced dramatically, while seismic CDF remained unchanged. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.44E-06	7.92	$32,820	4.40E-06	3.77E-05
Percent Change	0.0	9.9	2.6	68.3	0.0

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
Frequency_{BASE}	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
Frequency_{SAMA}	1.82E-08	1.66E-06	4.01E-06	1.23E-06	2.88E-07	1.23E-06	**8.44E-06**
Dose-Risk_{BASE}	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
Dose-Risk_{SAMA}	0.30	2.99	0.14	1.55	2.93	0.01	**7.92**
OECR_{BASE}	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
OECR_{SAMA}	$306	$11,932	$35	$8,346	$12,200	$1	**$32,820**

The Unit 1 cost risk associated with the Fire CDF reduction is $527,312. This value is the product of the SAMA-to-Base Fire CDF ratio (4.40E-06 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $1,120,096.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 11 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$6,223,579	$1,176,421

Based on a $4,651,776 cost of implementation for DCPP, the net value for this SAMA is -$3,475,355 ($1,176,421 - $4,651,776), which results in this SAMA not being cost beneficial.

F.6.9 SAMA 12: IMPROVE FIRE BARRIERS FOR ASW AND CCW EQUIPMENT IN THE CABLE SPREADING ROOM

Currently, the dominant DCPP fire scenarios are estimated to be those cable spreading room fires that result in damage to the ASW and CCW controls such that the evacuation to the hot shutdown panel would be required to maintain the plant in a safe state. Credit is not taken for the existing fire detection and suppression equipment in the cable spreading room, which may overestimate the risk posed from fires in this room. However, plant risk could be further reduced by improving fire barriers on the ASW and CCW equipment located in the cable spreading room. If control of these two systems could be maintained within the MCR by preventing damage to these systems, the challenge to the operators would be reduced.

Assumptions:

SAMA 12 reduces the impact of the CSR fire by shielding, wrapping or installing an incipient fire detection system. If the latter is installed, the ignition frequency may be reduced by at least 1.0E-2 (Reference 10). However, the reliability of incipient detectors to detect fires has neither been established nor accepted, but remains a future option. Note that implementation costs do not include incipient fire detection. Permanent fire watches and fire resistant wraps and cables (mineral filled) are other alternatives that may also mitigate the fire frequency or damage.

A combination of these features can either be reflected in initiator CSR1 or split fraction FEF6. As a bounding estimate, the initiating event frequency of CSR1 will be reduced by 1.0E-2. Only the sequences for initiator CSR1 are affected.

PRA Model Changes to Model SAMA:

Split Fraction: FEF6, FRE3

Top Event: FEF, FRE

A combination of these features can either be reflected in initiator CSR1 or split fraction FEF6. As a bounding estimate, the initiating event frequency of CSR1 will be reduced by 1.0E-2. Only the sequences for initiator CSR1 are affected.

Model Change(s):

Change CSR1 initiating event frequency from 6.7E-03 to 6.7E-05.

Results of SAMA Quantification:

Implementation of this SAMA yielded no reduction in the internal CDF, Dose-Risk and Offsite Economic Cost-Risk. Fire CDF was reduced dramatically, while seismic CDF remained unchanged. The results are summarized in the following table:

	Internal CDF	**Dose-Risk**	**OECR**	**Fire CDF**	**Seismic CDF**
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.44E-06	8.79	$33,699	8.27E-06	3.77E-05
Percent Change	0.0	0.0	0.0	40.5	0.0

As this SAMA represents ‘fire only’ risk, a further breakdown of the Dose-Risk and OECR information provided in the table below yields no additional insights:

Release Category	**ST1**	**ST2**	**ST3**	**ST4**	**ST5**	**ST6**	**Total**
Frequency_{BASE}	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
Frequency_{SAMA}	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
Dose-Risk_{BASE}	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
Dose-Risk_{SAMA}	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
OECR_{BASE}	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
OECR_{SAMA}	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**

The Unit 1 cost risk associated with the Fire CDF reduction is $984,015. This value is the product of the SAMA-to-Base Fire CDF ratio (8.27E-06 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $663,393.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 12 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$6,731,820	$668,180

Based on a $775,296 cost of implementation for DCPP, the net value for this SAMA is -$107,116 ($668,180 - $775,296), which results in this SAMA <u>not</u> being cost beneficial.

F.6.10 SAMA 13: IMPROVE CABLE WRAP FOR THE PORVS IN THE CABLE SPREADING ROOM

Cable Spreading Room fire scenarios are large contributors to CDF due to fires that result in the spurious opening of one or more PORVs due to hot short conditions and disable PORV block valve functionality. These scenarios can lead to unisolated LOCAs that require feed and bleed for mitigation. Protecting the PORV cables is a potential means of eliminating the PORV LOCAs.

<u>Assumptions:</u>

A combination of these features can either be accounted for in initiator CSR2 or split fraction FEF7. As a bounding estimate, the initiating event frequency of CSR2 will be reduced by 1.0E-2. Only the sequences for initiator CSR2 are affected.

<u>PRA Model Changes to Model SAMA:</u>

Split Fraction: FHS1, FPR1, FEF7

Top Event: FHS, FPR, FEF

Another cable spreading room (CSR) fire is modeled via initiating event CSR2 that uses event tree CSR2. There are only 5 split fractions assigned from 5 top events in this event tree:

FEF7 – probability fire extinguish before equipment fails (1.38E-01)
FHS1 – conditional probability of a hot short (2.88E-01)
FSU1 – conditional probability of a sustained hot short (1.38E-01)
FRE4 – recovery of equipment prior to LOCA (2.60E-04)
FPR1 – probability of PORV failing to reseat (1.42E-02)

This scenario models hot short damage to the PORV cables as well as damage to pressurizer pressure and temperature controls. Like SAMA 12, SAMA 13 reduces the impact of the CSR2 fires, and PORV damage, by shielding, wrapping or installing an incipient fire detection system. The reliability of incipient detectors to detect fires has neither been established nor accepted but remains an option. Note that implementation costs do not include incipient fire detection. Permanent fire watches and fire resistant wraps and cables (mineral filled) are other options that may also mitigate the fire frequency or damage.

Model Change(s):

Reduce CSR2 frequency by 1.0E-02

Results of SAMA Quantification:

Implementation of this SAMA yielded no reduction in the internal CDF, Dose-Risk and Offsite Economic Cost-Risk. Fire CDF was reduced significantly, while seismic CDF remained unchanged. The results are summarized in the following table:

	Internal CDF	**Dose-Risk**	**OECR**	**Fire CDF**	**Seismic CDF**
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.44E-06	8.79	$33,699	1.01E-05	3.77E-05
Percent Change	0.0	0.0	0.0	27.0	0.0

As this SAMA represents ‘fire only’ risk, a further breakdown of the Dose-Risk and OECR information provided in the table below yields no additional insights:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
$Frequency_{BASE}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$Frequency_{SAMA}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
Dose-$Risk_{BASE}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
Dose-$Risk_{SAMA}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
$OECR_{BASE}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
$OECR_{SAMA}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**

The Unit 1 cost risk associated with the Fire CDF reduction is $1,205,786. This value is the product of the SAMA-to-Base Fire CDF ratio (1.01E-05 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $441,622.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 13 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$6,953,595	$446,405

Based on a $775,296 cost of implementation for DCPP, the net value for this SAMA is -$328,891 ($446,405 - $775,296), which results in this SAMA being <u>not</u> cost beneficial.

F.6.11 SAMA 16: INSTALL AUTOMATIC SUPPRESSION IN VERTICAL BOARD 4 OF THE MCR

While automatic suppression systems are not assumed to prevent damage to the equipment associated with the fire initiator, automatic suppression could prevent propagation of the fire between power divisions. For MCR fires that start in Vertical Board 4, this capability could greatly reduce the risk of the fires.

<u>Assumptions:</u>

An improved capability for extinguishing a Vertical Board 4 fire can be modeled via a detection system or panel division fire suppression system. In either case, the improved likelihood of surviving the fire can be modeled by a 1.0E-2 reduction in the probability of failing to suppress the fire (see SAMA 12 for an estimated of the failure rate of a cabinet detection/suppression system).

<u>PRA Model Changes to Model SAMA:</u>

Split Fraction: FEF2

Top Event: FEF

Split fraction FEF2 models the probability of failing to extinguish a fire in the control room Vertical Board 4, modeled via fire initiating event VB4, before each train of equipment is disabled. Initiator VB4 is treated in event tree VB14 and is where split fractions FEF1 (for initiator VB1) and FEF2 (initiator VB4) are used.

This SAMA suggests installing cabinet fire detectors, suppression or improved division isolation in each panel to minimize the damage to a single train.

<u>Model Change(s):</u>

Reduce the failure probability of FEF2 (1.54E-02) by 1.0E-02, or to a new value of 1.54E-04.

<u>Results of SAMA Quantification:</u>

Implementation of this SAMA yielded no reduction in the internal CDF, Dose-Risk and Offsite Economic Cost-Risk. Fire CDF was reduced slightly, while seismic CDF remained unchanged. The results are summarized in the following table:

	Internal CDF	**Dose-Risk**	**OECR**	**Fire CDF**	**Seismic CDF**
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.44E-06	8.79	$33,699	1.35E-05	3.77E-05
Percent Change	0.0	0.0	0.0	2.6	0.0

As this SAMA represents 'fire only' risk, a further breakdown of the Dose-Risk and OECR information provided in the table below yields no additional insights:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
$Frequency_{BASE}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$Frequency_{SAMA}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$Dose\text{-}Risk_{BASE}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
$Dose\text{-}Risk_{SAMA}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
$OECR_{BASE}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
$OECR_{SAMA}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**

The Unit 1 cost risk associated with the Fire CDF reduction is $1,606,637. This value is the product of the SAMA-to-Base Fire CDF ratio (1.35E-05 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $40,771.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 16 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$7,354,560	$45,440

Based on a $3,944,318 cost of implementation for DCPP, the net value for this SAMA is -$3,898,878 ($45,440 - $3,944,318), which results in this SAMA not being cost beneficial.

F.6.12 SAMA 17: INSTALL ALTERNATE POWER CONNECTIONS TO CCP 1-2

Providing CCP 1-2 with alternate power connections would ensure RCS makeup would be available whenever at least one division of emergency power is available (assuming the pump is available). Installation of local connections and breaker controls would allow the alternate power alignment to be completed in time to provide makeup for the subsequent low leakrate (21 gpm per pump, 84 gpm total) RCP seal LOCA (which accounts for 78 percent of all seal LOCAs).

Assumptions:

There are several split fractions that model the charging system with the loss of AC power to either the train B pump or the train B pump and hardware. If alternate power is available through a separate breaker to train A power, these split fractions would be reduced by approximately 1.0E-01 (see split fraction CH1 for comparison to CH1A). The new values are provided below.

PRA Model Changes to Model SAMA:

Split Fraction: SE9F

Top Event: SE

Split fraction SE9F models the probability of a seal LOCA given the RCPs are tripped, loss of all seal injection and thermal barrier cooling. This split fraction is assigned for fire initiators FS1 through FS8 as well as fire initiators that begin Z* (charging is guaranteed failed for initiator FS2). These fire initiators make use of the general transient event tree GENTRAN where CH is the charging pump top event. This SAMA models a redundant AC breaker providing alternate power to charging pump CCP 12.

Model Change(s):

Split Fraction	Original Value	New Value	Split Fraction Description
CH1A	7.48E-03	7.48E-04	PUMP 12 UNAVAIL
CH3	1.52E-02	1.52E-03	SUPPORT TO CCP2/TRAIN B UNAVAILABLE
CH4A	1.52E-02	1.52E-03	PUMP 12 (TRAIN B) AND 480 F (TRAIN A) UNAVAILABLE
CH6A	8.03E-03	8.03E-04	PUMP 12 UNAVAIL – LOSP
CH8	1.58E-02	1.58E-03	SUPPORT TO CCP2/TRAIN B UNAVAILABLE - LOSP
CH9A	1.58E-02	1.58E-03	PUMP 12 (TRAIN B) AND 480V F (TRAIN A) UNAVAIL - LOSP
CHBA	7.90E-03	7.90E-04	PUMP 12 UNAVAIL – FIRE
CHD	1.37E-02	1.37E-03	SUPPORT TO CCP2/TRAIN B UNAVAILABLE - Fire Scenario
CHEA	1.37E-02	1.37E-03	PUMP 12 (TRAIN B) AND 480 F (TRAIN A) UNAVAIL - FIRE

Split Fraction	Original Value	New Value	Split Fraction Description
CHHA	1.17E-03	1.17E-04	PUMP 12 UNAVAIL - LOSP AND FIRE
CHJ	1.43E-02	1.43E-03	SUPPORT TO CCP2/TRAIN B UNAVAILABLE - LOSP - Fire Scenario
CHKA	1.43E-02	1.43E-03	PUMP 12 (TRAIN B) AND 480 F (TRAIN A) UNAVAIL - LOSP AND FIRE

Results of SAMA Quantification:

Implementation of this SAMA yielded negligible reductions in the internal CDF, Dose-Risk and Offsite Economic Cost-Risk. Similarly, fire and seismic CDF values remained unchanged. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.42E-06	8.79	$33,686	1.39E-05	3.77E-05
Percent Change	0.2	0.1	0.0	0.0	0.0

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
Frequency_{BASE}	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
Frequency_{SAMA}	7.15E-08	1.66E-06	3.96E-06	1.23E-06	2.88E-07	1.22E-06	**8.42E-06**
Dose-Risk_{BASE}	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
Dose-Risk_{SAMA}	1.17	2.98	0.13	1.55	2.93	0.01	**8.79**
OECR_{BASE}	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
OECR_{SAMA}	$1,201	$11,903	$35	$8,346	$12,200	$1	**$33,686**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 17 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$7,397,147	$2,853

Based on a $5,184,792 cost of implementation for DCPP, the net value for this SAMA is -$5,181,939 ($2,853 - $5,184,792), which results in this SAMA not being cost beneficial.

F.6.13 SAMA 18: SEISMICALLY QUALIFIED ALTERNATE 480V AC EDG TO SUPPORT LONG TERM AFW OPERATION AND A SEISMICALLY QUALIFIED 480V AC SELF-COOLED PDP FOR RCS MAKEUP

For seismic events that fail the site's 4KV AC systems, an alternate EDG could be used to power a station battery charger for SG level instrumentation and AFW control. In addition, if power can rapidly be supplied to a 480V AC self-cooled PDP, a manually connected, long term primary side makeup source would be available to mitigate RCP seal leakage. The generator and pump would have to be stored in a seismically qualified area. With minimum connection details for the supplied components, this SAMA is geared towards mitigating the higher probability (low leakrate) RCP seal LOCA (21 gpm per pump, 84 gpm total), which accounts for 78 percent of all seal LOCAs.

Assumptions:

Top event TD is only in the seismic general transient event tree (SGENTRAN) and models the turbine driven AFW pump. With the addition of an alternate independent power source to support TD AFW control and SG level indication the following split fraction changes should be made. There is no change to TD1 (all support systems available). TD2 can assume the same value as TD1 because of the extra power support. TDF is no longer a guaranteed failed, as self contained power source is available. So the degraded TD2 value is assigned to TDF. The split fraction rules are unaffected.

Top event CH models cold leg injection via the CCPs. Because this SAMA provides a redundant injection pump from a separate stand-alone AC power source, each split fraction in the SGENTRAN event tree can be reduced by the failure rate of such a system. The assumed failure rate is 1.0E-02. The guaranteed failed split fraction (CHF) is no longer 1.0E+00, but defaults to the failure rate of the stand-alone redundant train, 1.0E-02.

The case where top event TD fails because of the failure of the stand-alone power train as the only remaining control power source is ignored (in this instance split fraction CHF would need a new rule and would be assigned 1.00E+00).

Top event AW, which models all AFW pump trains is unaffected. Although the TD pump is part of the AW fault tree structure the status of TD is tracked in the split fraction rule assignments for AW.

<u>PRA Model Changes to Model SAMA:</u>

Split Fraction: SACSS3 – 6; SCT3 – 6; SOP2 – 6; etc.

Top Event: TD, CH

These split fractions represent seismically induced loss of AC power. Top event SACSS represents the loss of vital 4kV AC power given the turbine building structure did not fail (higher probabilities are assigned if the turbine building fails, see top event SACSF). Top event SCT represents the impact of seismic activity on relay chatter and the ability of the operators to reset them. While top event SOP represents the failure of offsite power given various seismic levels. Other top events affected include SDG which models the seismic fragility of all the emergency diesels (if this top event fails, all EDGs are failed), and the individual top events for the diesels GF, GG, and GH.

This SAMA represents installing a seismically robust, stand alone 480V AC power source that could provide power to the AFW level instrumentation as well as powering an additional high pressure injection (positive displacement) pump. Although the SAMA does not address the seismic loss of power directly as represented by these split fractions, it instead addresses turbine driven AFW control by providing power for level instrumentation and installs an additional high pressure pump for RCS inventory control.

Model Change(s):

Top Event TD

Split Fraction	Old Value	New Value
TD1	3.77E-02	Unchanged
TD2	9.96E-02	3.77E-02
TDF	1.00E+00	9.96E-02

Top Event CH

Split Fraction	Old Value	New Value
CH1	6.63E-04	6.63E-06
CH1A	7.48E-03	7.48E-05
CH1B	7.48E-03	7.48E-05
CH2	1.52E-02	1.52E-04
CH3	1.52E-02	1.52E-04
CH4	8.47E-03	8.47E-05
CH4A	1.52E-02	1.52E-04
CH5	8.47E-03	8.47E-05
CH5A	1.52E-02	1.52E-04
CH6	7.46E-04	7.46E-06
CH6A	8.03E-03	8.03E-05
CH6B	8.03E-03	8.03E-05
CH7	1.58E-02	1.58E-04
CH8	1.58E-02	1.58E-04
CH9	8.56E-03	8.56E-05
CH9A	1.58E-02	1.58E-04
CHA	8.56E-03	8.56E-05
CHAA	1.58E-02	1.58E-04
CHF	1.00E+00	1.00E-02

Results of SAMA Quantification:

Implementation of this SAMA yielded a marginal reduction in the CDF, and negligible changes in Dose-Risk and Offsite Economic Cost-Risk. Fire CDF was reduced nominally, while seismic CDF reduction was small. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	7.78E-06	8.80	$33,953	1.25E-05	3.71E-05
Percent Change	7.8	0.0	-0.8	10.1	1.6

It should be noted that, although nearly identical to SAMA 5, SAMA 18 results differed slightly based on the analysis targeting the turbine-driven AFW pump equipment, where the split fractions driving the case were seisimic LOSP. Hence, little credit was given to the motor-driven AFW pump as compared with SAMA 5, which resulted in slightly less risk improvement. Both SAMAs 5 and 18 have the same injection credit.

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
$Frequency_{BASE}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$Frequency_{SAMA}$	6.77E-08	1.79E-06	3.51E-06	1.23E-06	2.73E-07	9.05E-07	**7.78E-06**
$Dose\text{-}Risk_{BASE}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
$Dose\text{-}Risk_{SAMA}$	1.11	3.23	0.12	1.55	2.78	0.00	**8.80**
$OECR_{BASE}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
$OECR_{SAMA}$	$1,137	$12,886	$31	$8,335	$11,564	$1	**$33,953**

The Unit 1 cost risk associated with the Fire CDF reduction is $1,483,158. This value is the product of the SAMA-to-Base Fire CDF ratio (1.25E-05 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $164,250. Calculated in a similar manner, Seismic CDF averted cost risk is $70,828.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 18 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$7,142,371	$257,629

Based on a $6,441,418 cost of implementation for DCPP, the net value for this SAMA is -$6,183,789 ($257,629 - $6,441,418), which results in this SAMA not being cost beneficial.

F.6.14 SAMA 22: INSTALL A REDUNDANT ACTUATION SYSTEM FOR AFW

Failure of the SSPS system to actuate critical equipment followed by failure of the operators to manually start the systems can lead to core damage. Based on operator dependency issues, additional, manual recovery actions would provide limited benefit. Inclusion of a redundant means of actuating the AFW system on low SG level is a potential means of reducing the contribution of SSPS failures.

The current PRA model logic conservatively credits AMSAC as the only initiation signal for AFW. Upon further investigation, it was revealed that there are multiple AFW start signals, including non-SSPS signals that do not show up in the PRA model. This condition resulted in artificially high SF values that were used to identify this SAMA.

Keeping in mind the primary driver is seismic where trip of both main feedwater pumps should start both MDAFW pumps (with offsite AC power); the PRA model was subsequently requantified to simulate the ‘actual’ conditions. Crediting an AMSAC-like signal for AFW, the resulting (seismic CDF) RRW values for split fractions S12 and SB2 were reduced from 1.01 to 1.0001, which is below the review threshold of 1.01. Crediting the other non-modeled AFW signals in this manner will serve to further reduce the RRW values. Similarly, Level 2 RRW values for S12 and SB2 were reduced to 1.00, which further illustrates that the plant systems that are not modeled obviate the need for this SAMA.

F.6.15 SAMA 24: PREVENT CLEARING OF RCS COLD LEG WATER SEALS

This SAMA models the procedure change that would preclude the operators from clearing the water seals in the RCS cold legs after core damage. If the loop seals are cleared, there is an unobstructed flowpath for hot gases to flow from the damaged vessel through the steam generator tubes increasing the likelihood of an induced steam generator tube rupture.

<u>Assumptions:</u>

Similar to the procedure change modeled at Palo Verde for an equivalent SAMA, it is assumed that the likelihood of a thermally induced SGTR is reduced by a factor of 10 if this procedure is implemented.

<u>PRA Model Changes to Model SAMA:</u>

Split Fraction: ISCET1, ISCET2

Top Event: ISCET

Reduce the ISCET split fractions by a factor of ten. The guaranteed success split fraction is unaffected.

<u>Model Change(s):</u>

Split Fraction	Original Value	New Value
ISCET0	**0.00E+00**	**N/A**
ISCET1	5.8E-02	5.8E-03
ISCET2	7.1E-02	7.1E-03
ISCET3	7.1E-02	7.1E-03

Results of SAMA Quantification:

Implementation of this SAMA yielded a negligible reduction in the internal CDF, while Dose-Risk and Offsite Economic Cost-Risk were nominally reduced. No reduction in Fire and Seismic CDF was observed. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.43E-06	8.63	$32,758	1.39E-05	3.77E-05
Percent Change	0.1	1.9	2.8	0.0	0.0

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
$Frequency_{BASE}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$Frequency_{SAMA}$	7.28E-08	1.70E-06	4.03E-06	1.11E-06	2.77E-07	1.24E-06	**8.43E-06**
$Dose\text{-}Risk_{BASE}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
$Dose\text{-}Risk_{SAMA}$	1.19	3.07	0.14	1.40	2.83	0.01	**8.63**
$OECR_{BASE}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
$OECR_{SAMA}$	$1,222	$12,238	$36	$7,514	$11,747	$1	**$32,758**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 24 Net Value

UNIT	BASE CASE COST-RISK	REVISED COST-RISK	AVERTED COST-RISK
DCPP Unit 1	$7,400,000	$7,373,523	$26,477

Based on a $50,000 cost of implementation for DCPP, the net value for this SAMA is -$23,523 ($26,477 - $50,000), which results in this SAMA not being cost beneficial.

F.6.16 SAMA 25: FILL OR MAINTAIN FILLED THE STEAM GENERATORS TO SCRUB FISSION PRODUCTS

This SAMA makes a procedure change that directs operators to fill or maintain filled the steam generators just prior to core damage to provide mechanical scrubbing of fission products.

Assumptions:

It is assumed that the bulk of the effect of this action would be to change the end state of some LERF scenarios to SERF scenarios. Instead of the core damage scenarios resulting in a “large” fission product release outside the containment, the SG mechanical scrubbing action would reduce the fission product concentration to “small” levels.

PRA Model Changes to Model SAMA:

Split Fraction: AW, OR
Top Event: N/A

The base case LERF sequences were reviewed and reassigned. If the sequence had success of auxiliary feedwater (top event AW) then it became a candidate for reassignment. Next the sequences were looked at to see whether operators successfully executed cooldown and depressurization of the RCS (top event OR). If the operators were successful at cooldown and depressurization full credit was given for the action to fill the SGs just prior to core damage (1.00E-02 failure rate was assumed). These 2 operator actions are assumed to be dependent. If the operators failed to cooldown and depressurize then a higher failure rate was assumed for filling the SGs (1.00E-01 failure rate). The candidate sequences were multiplied by these factors, as shown below, to determine the new LERF frequency. LERF release categories that are applicable include: RC01, RC01U, RC02, RC02U, RC03, RC03U, RC04 and RC04U.

The following equations were used on the sequences that met these characteristics in each of the release categories mentioned above.

A) AW success * OR success * 1.00E-02 = LERF – failed to fill SG

B) AW success * OR success * (1 - 1.00E-02) = SERF – filled SG

C) AW success * OR fail * 1.00E-01 = LERF – failed to fill SG

D) AW success * OR fail * (1 - 1.00E-01) = SERF – filled SG

E) AW fail = LERF

Sequences and frequency from equations B) and D) were moved from LERF to SERF. The compliments of these, where the SG fill action failed, remained in LERF: A) and C). If sequences did not meet these characteristics they were not altered and remained in their original LERF endstate: E).

Results of SAMA Quantification:

Implementation of this SAMA yielded no reductions in the internal CDF, as well as Fire and Seismic CDF. Dose-Risk was appreciably reduced, while Offsite Economic Cost-Risk was only marginally reduced. The results are summarized in the following table:

	Internal CDF	**Dose-Risk**	**OECR**	**Fire CDF**	**Seismic CDF**
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.44E-06	8.03	$33,220	1.39E-05	3.77E-05
Percent Change	0.0	8.7	1.4	0.0	0.0

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	**ST1**	**ST2**	**ST3**	**ST4**	**ST5**	**ST6**	**Total**
Frequency_{BASE}	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
Frequency_{SAMA}	1.93E-08	1.71E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
Dose-Risk_{BASE}	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
Dose-Risk_{SAMA}	0.32	3.09	0.13	1.55	2.94	0.01	**8.03**
OECR_{BASE}	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
OECR_{SAMA}	$325	$12,312	$35	$8,347	$12,201	$1	**$33,220**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 25 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$7,359,492	$40,508

Based on a $50,000 cost of implementation for DCPP, the net value for this SAMA is -$9,492 ($40,508 - $50,000), which results in this SAMA not being cost beneficial.

F.6.17 SUMMARY

All of the SAMAs reviewed showed at least some benefit with respect to the traditional CDF and LERF risk metrics. None of the proposed SAMAs is cost beneficial at the nominal level when comparing the averted cost-risk to the associated implementation costs.

F.7 UNCERTAINTY ANALYSIS

The following three uncertainties were further investigated as to their impact on the overall SAMA evaluation:

- Use a discount rate of 7 percent, instead of 3 percent used in the base case analysis.
- Use the 95th percentile PRA results in place of the mean PRA results.
- Selected MACCS2 input variables.

F.7.1 REAL DISCOUNT RATE

A sensitivity study has been performed in order to identify how the conclusions of the SAMA analysis might change based on the value assigned to the real discount rate (RDR). The original RDR of 3 percent, which could be viewed as conservative, has been changed to 7 percent and the modified maximum averted cost-risk was re-calculated using the methodology outlined in Section F.4.

Phase 1 SAMAs are not impacted by use of the 7 percent RDR. Refer to Section F.5 and Table F.5-3 for a detailed analysis of each Phase 1 SAMA that was screened from further analysis.

The Phase 2 analysis was re-performed using the 7 percent RDR. Implementation of the 7 percent RDR reduced the MMACR by 26 percent compared with the case where a 3 percent RDR was used. This corresponds to a decrease in the MMACR from $7,400,000 to $5,453,800 per unit.

The Phase 2 SAMAs are dispositioned based on PRA insights or detailed analysis. All of the PRA insights used to screen the SAMAs are still applicable given the use of the 7 percent real discount rate as the change only strengthens the factors used to screen them. The SAMA candidates screened based on these insights are considered to be addressed and are not further investigated.

The remaining Phase 2 SAMAs were dispositioned based on the results of a SAMA specific cost-benefit analysis. This step has been re-performed using the 7 percent real discount rate to calculate the net values for the SAMAs.

As shown below, the determination of cost effectiveness did not change for any of the Phase 2 SAMAs when the 7 percent RDR was used in lieu of 3 percent.

Summary of the Impact of the RDR Value on the Detailed SAMA Analyses

SAMA ID	Cost of Implementation	Averted Cost Risk (3 percent RDR)	Net Value (3 percent RDR)	Averted Cost Risk (7 percent RDR)	Net Value (7 percent RDR)	Change in Cost Effectiveness?
2	$6,509,256	$76,141	($6,433,115)	$58,750	($6,450,506)	No
3	$5,863,176	$1,307,657	($4,555,519)	$962,734	($4,900,442)	No
5	$6,441,418	$288,568	($6,152,850)	$214,154	($6,227,264)	No
7	$2,552,563	$7,821	($2,544,742)	$6,749	($2,545,814)	No
8	$6,376,810	$1,235,004	($5,141,806)	$910,806	($5,466,004)	No
9	$1,692,730	$51,188	($1,641,542)	$38,073	($1,654,657)	No
10	$6,234,672	$1,897,895	($4,336,777)	$1,400,668	($4,834,004)	No
11	$4,651,776	$1,176,421	($3,475,355)	$865,924	($3,785,852)	No
12	$775,296	$668,180	($107,116)	$492,448	($282,848)	No
13	$775,296	$446,405	($328,891)	$328,999	($446,297)	No
16	$3,944,318	$45,440	($3,898,878)	$33,488	($3,910,830)	No
17	$5,184,792	$2,853	($5,181,939)	$2,131	($5,182,661)	No
18	$6,441,418	$257,629	($6,183,789)	$191,643	($6,249,775)	No
24	$50,000	$26,477	($23,523)	$18,994	($31,006)	No
25	$50,000	$40,508	($9,492)	$29,013	($20,987)	No

F.7.2 95TH PERCENTILE PRA RESULTS

The results of the SAMA analysis can be impacted by implementing conservative values from the PRA’s uncertainty distribution. If the best estimate failure probability values were consistently lower than the “actual” failure probabilities, the PRA model would underestimate plant risk and yield lower than “actual” averted cost-risk values for potential SAMAs. Re-assessing the cost-benefit calculations using the high end of the failure probability distributions is a means of identifying the impact of having consistently underestimated failure probabilities for plant equipment and operator actions included in the PRA model.

A Level 1 internal events model uncertainty analysis was not performed for DCPP model DC01A. However, an uncertainty analysis was performed on DCPP model DC00 in 2000. Since the 95th percentile assessment employs a ratio rather than individual values, a determination was made to use the DC00 uncertainty results. The basis for this decision is that the 95th to CDF point estimate ratio is not expected to vary significantly between the two models, and hence, should provide a representative value. The availability and use of Level 2 uncertainties is unique since most plants incorporate only Level 1 analyses in their SAMA reports. The reason Level 2 analyses are not typically used is due to the differing degree of development and uncertainties between the two models. Specifically, the Level 1 model tends to represent the plant in a more thorough and comprehensive manner as opposed to the Level 2 model. Furthermore, there are more release contributors beyond those captured by LERF. As such, for the purposes of the 95th percentile analysis, only Level 1 results are used in the uncertainty process. The results of the Level 1 calculation are provided below.

In performing the sensitivity analysis, only the base case was used in determining the appropriate value for the 95th percentile. For those SAMAs that required the addition of new basic events, no new uncertainty distributions were assigned since the design and implementation of each SAMA was arbitrary and was defined by the analysis assumptions. The results of this uncertainty analysis, therefore, show the expected statistical uncertainty of the CDF risk metrics under the assumption that each SAMA was designed and implemented as it was specified in this analysis. All RISKMAN calculations were performed with RISKMAN Release 8.0 on a DELL OptiPlex GX1 Pentium II (S/N GVXHF), using WINDOWS 95, which has been certified for use with RISKMAN in RFA ISAG 24 Add. 1 (Reference 43). The calculation file documents the quantification of the top event split fractions using the Monte Carlo option to obtain the probability distribution for each split fraction. The steps for performing the Monte Carlo quantification of the split fractions are outlined below:

- Four batch runs of top event split fractions
- Each batch run used the same parameters
- Quantification option - Monte Carlo

The calculational results of this uncertainty calculation are shown in the table below. The term CDF_{pe} refers to the nominal CDF point estimate of 1.41E-05.

Summary of Uncertainty Distribution

Mean	5%	50%	95%	Factor > CDF_{pe}	Std Dev
1.56E-05	6.56E-06	1.24E-05	3.33E-05	2.36	1.98E-10

The above table reveals a factor that is 2.36 greater than the respective point estimate CDF, which is in agreement with industry experience. Therefore, for this analysis, the 95th percentile for the base case is used to examine the change in the cost benefit for each SAMA.

F.7.2.1 PHASE 1 IMPACT

For Phase 1 screening, use of the 95th percentile PRA results will increase the MACR and may prevent the screening of some of the higher cost modifications. However, the impact on the overall SAMA results due to the retention of the higher cost SAMAs for Phase 2 analysis is typically small. This is due to the fact that the benefit obtained from the implementation of those SAMAs must be extremely large in order to be cost beneficial.

The impact of uncertainty in the PRA results on the Phase 1 SAMA analysis has been examined. The MACR is the primary Phase 1 criteria affected by PRA uncertainty. Thus, this portion of the sensitivity is focused on recalculating the MACR using the 95th percentile PRA results and re-performing the Phase 1 screening process. As discussed above, the 95th PRA results are a factor of 2.36 greater than the point estimate CDF.

The uncertainty analyses that are available for the Level 1 models are not available for Level 2 and Level 3 PRA models. In order to simulate the use of the 95th percentile results for the Level 2 and Level 3 models, the same scaling factor calculated for the Level 1 results was assumed to apply to the Level 2 and Level 3 models. Because the MACR calculations scale linearly with the CDF, dose-risk, and off-site economic cost-risk, the 95th percentile MACR can be calculated by multiplying the base case MACR by 2.36. This results in a 95th percentile MACR of $17,464,000.

The initial SAMA list has been re-examined using the revised MACR to identify SAMAs that would have been retained for the Phase 2 analysis. Those SAMAs that were previously screened due to costs of implementation that exceeded $7.4 million are now retained if the costs of implementation are less than $17,464,000. Of the SAMAs screened in the baseline Phase 1 analysis, SAMAs 6, 14, 15, 19 and 20 would be retained based on the use of the 95th percentile MACR.

Based on detailed quantifications of each Phase 1 SAMA listed above, new averted cost risk and net values at the 95th percentile were generated. As shown below, none of the SAMAs produced positive net values. In fact, the net values for each SAMA were significantly negative, providing further justification of screening them from consideration.

F.7.2.1.1 SAMA 6: Use Alternate Engine-Driven HP Pump for Secondary Side Makeup

Ensuring that an alternate, engine-driven, HP pump could be rapidly aligned to provide secondary side makeup in transient scenarios could address many loss of AFW scenarios. This may require pre-staging equipment in seismically qualified areas and ensuring the pump and piping can be quickly aligned to the AFW injection line/suction source. If a higher pressure pump is required so that the system can be used to mitigate early loss of secondary side makeup cases, the cost should account for this.

Results of SAMA Quantification:

Implementation of this SAMA yielded significant reductions in the internal CDF, Dose-Risk and Offsite Economic Cost-Risk. Fire and Seismic CDF were marginally reduced. The results are summarized in the following table:

SAMA 6 PRA Model Results

	CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	6.73E-06	6.49	$25,250	1.34E-05	3.70E-05
Percent Change	20.2	26.2	25.1	3.8	1.9

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

SAMA 6 Internal Events Results By Release Category

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
$Frequency_{BASE}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$Frequency_{SAMA}$	5.71E-08	7.20E-07	3.42E-06	1.23E-06	2.54E-07	1.05E-06	**6.73E-06**
$Dose\text{-}Risk_{BASE}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
$Dose\text{-}Risk_{SAMA}$	0.94	1.30	0.12	1.55	2.59	0.01	**6.49**
$OECR_{BASE}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
$OECR_{SAMA}$	$959	$5,171	$30	$8,325	$10,763	$1	**$25,250**

The Unit 1 cost risk associated with the Fire CDF reduction is $1,584,335. This value is the product of the SAMA-to-Base Fire CDF ratio (1.34E-05 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $63,073. Calculated in a similar manner, Seismic CDF averted cost risk is $85,468.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 6 Net Values

Implementation Cost (per unit)	Averted Cost Risk (Base)	Net Value (Base)	Averted Cost Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effectiveness?
$14,475,422	$466,122	($14,009,300)	$1,100,015	($13,375,408)	No

Given that the cost of implementation is greater than the 95th percentile averted cost-risk for this SAMA, the net value remains negative.

F.7.2.1.2 SAMA 14: Fully Automate Feed and Bleed Initiation

In some fire scenarios where MCR abandonment is required or when rapidly evolving scenarios overload operators with required tasks, automation of the feed and bleed action could improve its reliability.

Assumptions:

This SAMA considers developing instrumentation that would indicate that loss of all secondary side cooling has occurred signaling the urgent need to initiate feed and bleed cooling. Assuming the hardware failure rate is similar to 2 trains of SSPS (see split fraction S12), it is approximately 5.0E-04. For fires, the appropriate location to model this is by either altering the value of split fraction FRE4 or FPR1. See SAMA 13 discussion for the treatment in the model for fire initiator CSR2. Since FPR1 models the PORV failing to reseat, it can be multiplied by failure of a feed and bleed signal.

For all other initiators, the appropriate location is in top event OB, which models feed and bleed. This top event is dominated by the human action to initiate feed and bleed (basic event OB-HE, and HEP data variable ZHEOB1 = 1.101E-02) and would be replaced by the 2 train SSPS-like signal failure rate.

PRA Model Changes to Model SAMA:

Split Fraction: FHS1, FPR1, FEF7

Top Event: FHS, FPR, FEF

This SAMA addresses the same cable spreading room (CSR) fire as SAMA 13 for initiator CSR2 (see above). In this instance the SAMA addresses automating systems necessary to mitigate the presumed resultant LOCA due to the stuck open PORV, specifically primary system feed and bleed cooling.

Model Changes(s):

For fire initiator CSR2, change the value of split fraction FPR1 (PORV failing to reseat, include the automatic system here) from 1.42E-02 to 7.10E-06 (1.42E-02 x 5.0E-04).

For all other initiators, change the value of top event OB split fractions by removing the contribution from the feed and bleed human action and adding in the SSPS-like instrument signal (-1.1011E-02+5.00E-04). Split fraction OBF models loss of feed and bleed because of loss of PORV support systems and is unchanged.

SF Name	Old Value	New Value	Split Fraction Description
OB1	2.26E-02	1.21E-02	Loss of Instrument Air - PORV 474 DISABLED
OB2	2.26E-02	1.21E-02	Loss of Instrument Air, Charging failed - PORV 474 DISABLED
OB3	1.18E-02	1.33E-03	ALL SUPPORT AVAILABLE
OBF	1.00E+00	unchanged	Guaranteed Failure

Results of SAMA Quantification:

Implementation of this SAMA yielded a marginal reduction in the internal CDF, and negligible reductions in Dose-Risk and Offsite Economic Cost-Risk. Fire CDF was reduced significantly, while seismic CDF remained unchanged. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.26E-06	8.75	$33,606	1.02E-05	3.77E-05
Percent Change	2.1	0.5	0.3	27.0	0.0

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
$\text{Frequency}_{\text{BASE}}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$\text{Frequency}_{\text{SAMA}}$	7.00E-08	1.66E-06	3.91E-06	1.23E-06	2.87E-07	1.11E-06	**8.26E-06**
$\text{Dose-Risk}_{\text{BASE}}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
$\text{Dose-Risk}_{\text{SAMA}}$	1.15	2.98	0.13	1.55	2.93	0.01	**8.75**
$\text{OECR}_{\text{BASE}}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
$\text{OECR}_{\text{SAMA}}$	$1,176	$11,897	$34	$8,314	$12,183	$1	**$33,606**

The Unit 1 cost risk associated with the Fire CDF reduction is $1,206,852. This value is the product of the SAMA-to-Base Fire CDF ratio (1.02E-05 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $440,556.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 14 Net Values

Implementation Cost (per unit)	Averted Cost Risk (Base)	Net Value (Base)	Averted Cost Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effective-ness?
$11,435,616	$455,246,	($10,980,370)	$1,074,348	($10,361,268)	No

Given that the cost of implementation is greater than the 95th percentile averted cost-risk for this SAMA, the net value remains negative.

F.7.2.1.3 SAMA 15: Provide Hard Piped Connection between Fire Water and the Charging Pump Lube Oil Coolers and Remotely-Operated MOVs

For certain combinations of AC power division failures (especially fire events), the self-cooled charging pump could be unavailable and the remaining charging pump is vulnerable to loss of CCW events. Enhancing the connection between Fire Water and CCP lube oil cooling so that it can be aligned in a timely manner can prevent failure of the charging pumps and provide makeup for the subsequent low leakrate (21 gpm per pump, 84 gpm total) RCP seal LOCA (which accounts for 78 percent of all seal LOCAs). Use of a hard pipe connection with remotely-operated isolation MOVs should reduce operator response by decreasing manipulation time and eliminating the alignment action actions.

<u>Assumptions:</u>

This hardware change can be achieved by installing a 1E powered MOV connecting the Fire Water system to the lube oil cooler. The power to the valve should be from the same power train as the charging pump. The failure rate for a valve to open on demand is 2.0E-03 (see ZTVMOD). Remote-manual actuation from the control room upon high oil temperature alarm or loss of all CCW is conservatively estimated to have a failure rate of 3.77E-04 (1.57E-05 * 24 hrs see ZTTRTR). Including breakers, temperature switches and MOV failure rates, the probability of failure of a backup source of water would be about 5.0E-03.

<u>PRA Model Changes to Model SAMA:</u>

Split Fraction: CC4GH

Top Event: CC

Split fraction CC4GH models the probability of the loss of (the remaining train of) CCW given the loss of 4kV buses G and H, i.e. only the train powered by bus F remains available. When the last single train of CCW is lost (CC4GH) then the remaining charging pump (CCP 11, powered from 4kV bus F) fails due to lack of CCW to the lube oil cooler. SAMA 15 models the alignment of Fire Water to charging pump 11's lube oil cooler.

Model Change(s):

Reduce split fraction CC4GH (1.52E-02) by 5.0E-03 to 7.6E-05.

Results of SAMA Quantification:

Implementation of this SAMA yielded negligible reductions in the internal CDF, Dose-Risk and Offsite Economic Cost-Risk. Fire CDF was reduced marginally, while seismic CDF remained unchanged. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.36E-06	8.75	$33,532	1.30E-05	3.77E-05
Percent Change	0.9	0.5	0.5	6.8	0.0

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
$Frequency_{BASE}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$Frequency_{SAMA}$	7.16E-08	1.64E-06	3.95E-06	1.23E-06	2.87E-07	1.18E-06	**8.36E-06**
$Dose\text{-}Risk_{BASE}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
$Dose\text{-}Risk_{SAMA}$	1.17	2.96	0.13	1.55	2.93	0.01	**8.75**
$OECR_{BASE}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
$OECR_{SAMA}$	$1,203	$11,788	$35	$8,320	$12,185	$1	**$33,532**

The Unit 1 cost risk associated with the Fire CDF reduction is $1,537,341. This value is the product of the SAMA-to-Base Fire CDF ratio (1.30E-05 / 1.39E-05) multiplied by the per-unit Fire MACR ($1,647,408). The resultant averted cost risk is $110,067.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 15 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
DCPP Unit 1	$7,400,000	$7,277,333	$122,667

Given that the cost of implementation is greater than the 95th percentile averted cost-risk for this SAMA, the net value remains negative.

F.7.2.1.4 SAMA 19: Replace Critical Relays with High Seismic Capacity Relays

Relays in the emergency power circuit are assumed to be vulnerable to very high seismic activity, which can lead to interruptions in the availability of emergency 4KV AC power. Replacing the relays with designs that are more seismically durable could prevent relay faults due to very large seismic events.

<u>Assumptions:</u>

Assume that the relay chatter failure rate drops by a factor of 100 for all “g” level ranges below, i.e. each split fraction is reduced by 100. This would model a more robust relay but not one that is completely resistant to chatter.

<u>PRA Model Changes to Model SAMA:</u>

Split Fraction: OC1SC; OC1SB; SCT3, 4, 5, 6; GXGS, GXHS

Top Event: SCT

Seismic relay chatter is modeled in top event SCT in the seismic general transient event tree SGENTRAN. SCT is dependent upon the “g” level of the seismic event, prescribing higher failure rates for higher “g” levels. Top event OC models the probability of operators failing to reset relays given a seismic event. The operator failure probabilities also increase with increasing “g” levels. GXGS and GXHS are intermediate split fraction values used by electric power top events GG and GH respectively. They are only slightly higher in probability than their non-seismic counterparts.

This SAMA suggests changing the current plant relays to more robust relays that are more resistant to seismic induced chatter.

Model Change(s):

Split Fraction	Base Value	Assumed Value
SCT1 – chatter for SEIS1	2.53E-04	2.53E-06
SCT2 – chatter for SEIS2	2.01E-02	2.01E-04
SCT3 – chatter for SEIS3	6.83E-02	6.83E-04
SCT4 – chatter for SEIS4	1.34E-01	1.34E-03
SCT5 – chatter for SEIS5	2.72E-01	2.72E-03
SCT6 – chatter for SEIS6	4.51E-01	4.51E-03

Results of SAMA Quantification:

Implementation of this SAMA yielded negligible reductions in the internal CDF, Dose-Risk, Offsite Economic Cost-Risk and fire CDF. Seismic CDF was reduced nominally. The results are summarized in the following table:

SAMA 19 PRA Model Results

	CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.43E-06	8.79	$33,689	1.39E-05	3.47E-05
Percent Change	0.1	0.1	0.0	0.0	8.0

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

SAMA 19 Internal Events Results By Release Category

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
$Frequency_{BASE}$	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
$Frequency_{SAMA}$	7.17E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.43E-06**
$Dose\text{-}Risk_{BASE}$	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
$Dose\text{-}Risk_{SAMA}$	1.18	2.98	0.13	1.55	2.93	0.01	**8.79**
$OECR_{BASE}$	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
$OECR_{SAMA}$	$1,205	$11,902	$35	$8,346	$12,200	$1	**$33,689**

The Unit 1 cost risk associated with the Seismic CDF reduction is $4,114,369. This value is the product of the SAMA-to-Base Seismic CDF ratio (3.47E-05 / 3.77E-05) multiplied by the per-unit Seismic MACR ($4,468,148). The resultant averted cost risk is $353,779.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 19 Net Values

Implementation Cost (per unit)	Averted Cost Risk (Base)	Net Value (Base)	Averted Cost Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effective-ness?
$15,312,096	$357,820	($14,954,276)	$844,430	($14,467,666)	No

Given that the cost of implementation is greater than the 95th percentile averted cost-risk for this SAMA, the net value remains negative.

F.7.2.1.5 SAMA 20: Use Alternate Signal (such as AMSAC) to De-energize the 480V AC Busses that Supply the Rod Drive Motor Generator Sets

In the event that the MG set breakers do not trip in an ATWS, an alternate signal, such as an AMSAC signal, could be used to depower the 480V AC supply that powers the

MG sets to ensure the control rod drive units are shut down. The 480V trip could be delayed so that it is only performed after 30 seconds with a valid ATWS signal.

Assumptions:

Reduce the probability of all split fractions for top event RT by the failure rate of an AMSAC-like system (use split fraction AM1), which is approximately 1.0E-02. No split fraction should be less than RT6 (6.16E-06) which is the failure probability of the control rods to insert. Split fraction RT6 is used for station blackout scenarios where it is certain the RPS bus has de-energized.

PRA Model Changes to Model SAMA:

Split Fraction: RT1S (intermediate RT1SE), RT4S (intermediate RT4SE), SA1, SB1

Top Event: RT

Top event RT models failure of the reactor trip breakers to open, the control rods to drop in the core, and the operators to de-energize the RPS bus if it does not occur automatically (see HEP ZHERT2). Split fractions RT1S and RT4S are used for seismic initiators. Failure of RT results in an ATWS event. RT is dependent on the success of SSPS (top events SA and SB), but the split fraction assignments for SSPS do not depend on seismic initiators, only power support. Split fractions SA1 and SB1 are assigned for most all initiator types.

This SAMA suggests providing a backup de-energize signal to the RPS bus in addition to the operator action. A source of that signal could come from a system like AMSAC (see top event AMA and AMB). The likelihood of failure of 2 trains of AMSAC (intermediate split fraction AM1) is 9.29E-03. AMSAC however has a poor seismic fragility and is guaranteed failed for all seismic initiators. This alternate signal source would have to have a robust seismic fragility. However, it’s design and components could be similar to AMSAC.

Model Change(s):

Split Fraction	Base Value	Assumed Value	Description
RT1	8.80E-06	6.16E-06	1/2 TRAINS (BOTH SSPS SIGNALS GENERATED)
RT1S	8.51E-05	6.16E-06	1/2 TRAINS (BOTH SSPS SIGNALS GENERATED) - SEIS W/ESAM=30
RT2	9.12E-06	6.16E-06	1/2 TRAINS (DC POWER LOST TO ONE SHUNT TRIP COILS)
RT2S	9.49E-05	6.16E-06	1/2 TRAINS (DC POWER LOST TO ONE SHUNT TRIP COILS) - SEIS W/ESAM=30
RT3	1.50E-05	6.16E-06	1/2 TRAINS (DC POWER LOST TO BOTH SHUNT TRIP COILS)
RT3S	2.72E-04	6.16E-06	1/2 TRAINS (DC POWER LOST TO BOTH SHUNT TRIP COILS) - SEIS W/ESAM=30
RT4	1.10E-04	6.16E-06	1/1 TRAIN (ONLY ONE SSPS SIGNAL GENERATED)
RT4S	3.12E-03	3.12E-05	1/1 TRAIN (ONLY ONE SSPS SIGNAL GENERATED) - SEIS W/ESAM=30
RT5	1.90E-04	6.16E-06	1/1 TRAIN (ONE SSPS SIGNAL, LOP TO SHUNT TRIP COIL)
RT5S	5.51E-03	5.51E-05	1/1 TRAIN (ONE SSPS SIGNAL, LOP TO SHUNT TRIP COIL) - SEIS W/ESAM=30
RT6	6.16E-06	Unchanged	GRAVITY INSERTION (INSUFFICENT POWER TO PREVENT INSERTION)1/1 TRAIN (ONE SSPS SIGNAL, LOP TO SHUNT TRIP COIL)GRAVITY INSERTION (INSUFFICENT POWER TO PREVENT INSERTION)
RT6S	6.16E-06	Unchanged	GRAVITY INSERTION (INSUFFICENT POWER TO PREVENT INSERTION)1/1 TRAIN (ONE SSPS SIGNAL, LOP TO SHUNT TRIP COIL)GRAVITY INSERTION (INSUFFICENT POWER TO PREVENT INSERTION) - SEIS W/ESAM=301/1 TRAIN (ONE SSPS SIGNAL, LOP TO SHUNT TRIP COIL)
RT7	3.10E-04	6.16E-06	OPERATOR INITIATED (DC POWER LOST TO BOTH SHUNT COILS)
RT7S	9.13E-03	9.13E-05	OPERATOR INITIATED (DC POWER LOST TO BOTH SHUNT COILS) - SEIS W/ESAM=30

Results of SAMA Quantification:

Implementation of this SAMA yielded negligible reductions in the internal CDF, Dose-Risk, Offsite Economic Cost-Risk and fire CDF. Seismic CDF was reduced nominally. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR	Fire CDF	Seismic CDF
Base Value	8.44E-06	8.79	$33,699	1.39E-05	3.77E-05
SAMA Value	8.36E-06	8.75	$33,558	1.39E-05	3.47E-05
Percent Change	0.9	0.5	0.4	0.0	8.1

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	ST1	ST2	ST3	ST4	ST5	ST6	Total
Frequency_{BASE}	7.18E-08	1.66E-06	3.97E-06	1.23E-06	2.88E-07	1.22E-06	**8.44E-06**
Frequency_{SAMA}	7.15E-08	1.64E-06	3.91E-06	1.23E-06	2.88E-07	1.22E-06	**8.36E-06**
Dose-Risk_{BASE}	1.18	2.99	0.13	1.55	2.94	0.01	**8.79**
Dose-Risk_{SAMA}	1.17	2.96	0.13	1.55	2.93	0.01	**8.75**
OECR_{BASE}	$1,206	$11,919	$35	$8,327	$12,211	$1	**$33,699**
OECR_{SAMA}	$1,201	$11,797	$34	$8,333	$12,191	$1	**$33,558**

The Unit 1 cost risk associated with the Seismic CDF reduction is $4,110,889. This value is the product of the SAMA-to-Base Seismic CDF ratio (3.47E-05 / 3.77E-05) multiplied by the per-unit Seismic MACR ($4,468,148). The resultant averted cost risk is $357,249.

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 20 Net Values

Implementation Cost (per unit)	Averted Cost Risk (Base)	Net Value (Base)	Averted Cost Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effective-ness?
$7,526,832	$367,847	($7,158,985)	$868,093	($6,658,739)	No

Given that the cost of implementation is greater than the 95th percentile averted cost-risk for this SAMA, the net value remains negative.

F.7.2.2 PHASE 2 IMPACT

As discussed above, a single factor based on the 95th percentile for the base case is used to determine the impact of the cost-benefit analysis for the proposed SAMA candidates. The uncertainty analyses that are available for the Level 1 model are not available (or not used) for the Level 2 and 3 PRA models. In order to simulate the use of the 95th percentile results for the Level 2 and 3 models, the same scaling factor calculated for the Level 1 results was implicitly applied to the Level 2 and 3 models.

The Phase 2 SAMA list was re-examined by multiplying the nominal averted cost risk by the ratio of the 95th percentile to the nominal CDF value (see Section F.7.2) to identify SAMAs that would be re-characterized as cost beneficial, i.e., positive net value. Those SAMAs that were previously determined to be not cost beneficial due to implementation costs exceeding their associated nominal averted cost risk may be potentially cost beneficial at the revised 95th percentile averted cost risk. In this case, three additional Phase 2 SAMAs become cost beneficial.

As explained in Section F.7.2.1 above, no Phase 1 SAMAs were retained in the Phase 2 analysis when utilizing the 95th percentile PRA results, since these SAMAs were dispositioned independently of implementation cost.

F.7.2.3 95TH PERCENTILE SUMMARY

The following table provides a summary of the impact of using the 95th percentile PRA results on the detailed cost-benefit calculations that have been performed.

Summary of the Impact of Using the 95th Percentile PRA Results

SAMA ID	Cost of Implementation	Averted Cost Risk (Base)	Net Value (Base)	Averted Cost Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effective-ness?
2	$6,509,256	$76,141	($6,433,115)	$179,687	($6,329,569)	No
3	$5,863,176	$1,307,657	($4,555,519)	$3,085,978	($2,777,198)	No
5	$6,441,418	$288,568	($6,152,850)	$681,000	($5,760,418)	No
7	$2,552,563	$7,821	($2,544,742)	$18,457	($2,534,106)	No
8	$6,376,810	$1,235,004	($5,141,806)	$2,914,522	($3,462,288)	No
9	$1,692,730	$51,188	($1,641,542)	$120,800	($1,571,930)	No
10	$6,234,672	$1,897,895	($4,336,777)	$4,478,898	($1,755,774)	No
11	$4,651,776	$1,176,421	($3,475,355)	$2,776,270	($1,875,506)	No
12	$775,296	$668,180	($107,116)	$1,576,857	$801,561	Yes
13	$775,296	$446,405	($328,891)	$1,053,484	$278,188	Yes
16	$3,944,318	$45,440	($3,898,878)	$107,235	($3,837,083)	No
17	$5,184,792	$2,853	($5,181,939)	$6,733	($5,178,059)	No
18	$6,441,418	$257,629	($6,183,789)	$607,986	($5,833,431)	No
24	$50,000	$26,477	($23,523)	$62,484	$12,484	Yes
25	$50,000	$40,508	($9,492)	$95,596	$45,596	Yes

When the 95th percentile PRA results are used, four of the Phase 2 SAMAs (12, 13, 24 and 25) that were previously classified as not cost effective are now determined to be cost effective. The use of the 95th percentile PRA results is not considered to provide the most rational assessment of the cost effectiveness of a SAMA; however, these additional SAMAs should be considered for implementation to address the uncertainties inherent in the SAMA analysis.

F.7.3 MACCS2 INPUT VARIATIONS

The MACCS2 model was developed using the best information available for the DCPP site; however, reasonable changes to modeling assumptions can lead to variations in the Level 3 results. In order to determine how certain assumptions could impact the SAMA results, a sensitivity analysis was performed on parameters that have previously been shown to impact the Level 3 results. These parameters include:

- Meteorological data
- Evacuation timing and speed
- Release height and heat
- Population estimates
- Population resettlement planning
- Generic economic inputs
- Economic rate of return

The risk metrics produced by MACCS2 that are evaluated in the sensitivity analyses are the 50 mile population dose and the 50 mile offsite economic cost. The subsections below discuss the changes in these results for each of the sensitivity parameters noted above. The final subsection, F.7.3.8, correlates the worst case changes identified in the sensitivity runs to a change in the site's averted cost-risk and discusses the implications of the sensitivity analysis on the SAMA analysis.

Sensitivity of DCPP Baseline Risk to Parameter Changes

Parameter	Description	Pop. Dose Risk Δ Base (%)	Cost Risk Δ Base (%)
Meteorology	Year 2004 Meteorology	-8	-3
	Year 2006 Meteorology	-8	-1
Evacuation Speed	Average evacuation speed decreased 50 percent from 0.4 m/sec to 0.2 m/sec.	+3	0
Evacuation Time	Evacuation delay time increased from 75 minutes to 150 minutes (factor of 2)	-5	0
Release Height	Release height set to ground level (in lieu of top of containment).	-6	-5

Sensitivity of DCPP Baseline Risk to Parameter Changes

Parameter	Description	Pop. Dose Risk Δ Base (%)	Cost Risk Δ Base (%)
Release Heat	Buoyant plume assumed (10 MW for each plume segment, except for intact containment release).	-8	+1
Population	Year 2045 population uniformly increased 30 percent	+30	+29
Resettlement Planning	No “Intermediate Phase” resettlement planning (in lieu of 6 months)	+10	-32
	1 year “Intermediate Phase” resettlement planning (in lieu of 6 months)	-6	+30
Generic Economic Data	Generic economic inputs (non-site specific values) increased by a factor of 2	-2	+45
Rate of Return	3 percent expected rate of return (in lieu of 7 percent)	+1	-8
	12 percent expected rate of return (in lieu of 7 percent)	-1	+10

F.7.3.1 METEOROLOGICAL SENSITIVITIES

In addition to the year 2002 base case meteorological data, years 2004 and 2006 were also analyzed. Analysis of year 2004 and 2006 data sets yielded population dose-risks and cost risks that were 1 percent to 8 percent less than 2002 results. As no particular criteria have been defined by the industry related to determining which meteorological data set should be used as a base case for a site, the year 2002 data is chosen for DCPP given that it results in higher results than the other data sets evaluated.

F.7.3.2 EVACUATION SENSITIVITIES

The sensitivity of two evacuation parameters was assessed. The evacuation speed sensitivity decreased the average radial evacuation speed by a factor of two, from 0.4 m/sec (0.9 mph) to 0.2 m/sec (0.45 mph). The decreased speed results in a relatively minor increase in population dose of 3 percent. One reason the increase is minor is the slow evacuation speed of the base case as compared to the average wind speed of approximately 4.5 m/sec (10 mph). This was the approximate average wind speed for each of the years of data finalized (2002, 2004, 2006) for MACCS2 analysis.

For either evacuation speed, the plumes can be viewed as tending to blow over and past the evacuees as the evacuees progress in traffic.

The delay time to evacuation (increased from 75 minutes to 150 minutes) was found to decrease the dose risk by approximately 5 percent. For many evacuation conditions, the population dose would be expected to increase for an increased delay time to evacuation since more individuals would be expected to be exposed to the release due to a later departure (i.e., evacuees fail to outrun the plumes). The dose decrease is primarily attributed to the release characteristics of the LGEARLY and ISLOCA release categories (i.e., first plumes < 1 hour in duration with significant CsI release fractions), relatively short interval between the GE time and the release of the first plume (i.e., 1 hour or less for LGEARLY, ISLOCA, and SMEARLY release categories), and the relatively show evacuation speed of 0.4 m/sec (0.9 mph) compared to the average wind speed of about 4.5 m/sec (10 mph). For the base case, evacuee movement would tend to begin slightly before or nearly coincident with the arrival of the first plume for LGEARLY, ISLOCA, and SMEARLY (depending upon the evacuees' distance from the site). At this time, individuals are leaving their homes (which provide some radiological shielding) and traveling in their vehicles (which provide less radiological shielding). With the modeled evacuation speed as compared to the average wind speed, individuals tend to have plumes pass over them as they progress in traffic. When the delay time is doubled to 150 minutes, the evacuation vehicle movement for more individuals will begin after the first plume of the LGEARLY, ISLOCA, and SMEARLY has passed while the individuals are afforded more radiological shielding in their homes. Thus, this sensitivity case demonstrates potential benefits of delayed evacuation for certain sets of conditions (e.g., release characteristics, meteorological conditions, evacuation speeds) which are accident specific, and that the base case provides generally conservative results for the metrics of interest for SAMA.

It is noted that while evacuation assumptions do impact the population dose-risk estimates, they do not impact MACCS2 offsite economic cost-risk estimates because MACCS2 calculated cost-risks are based on land contamination levels which remain unaffected by evacuation assumptions and the number of people evacuating.

F.7.3.3 RELEASE HEIGHT & HEAT SENSITIVITIES

The release height sensitivity case quantifies the impact of the assumption related to the height of the release of the plumes. The baseline case assumes that the releases occur near the top of reactor building (67m) which tends to disperse material over a wider geographical region, generally impacting more people and creating larger cleanup costs. A ground level release height shows a decrease in dose risk and cost risk of 6 percent and 5 percent, respectively.

The release heat sensitivity case evaluates the impact of neglecting thermal plume effects. The base case assumed no thermal plume heat in the releases (e.g., no buoyant plumes). The sensitivity case assumed a heat content of 10 MW per plume segment, except for the intact containment release category. Increasing the plume heat contents resulted in differing results for individual releases (i.e., results of some release categories increased while others decreased.) The net result is a decrease in dose-risk of 8 percent and an increase in cost risk of 1 percent when 10 MW plume heat content values are applied.

F.7.3.4 POPULATION SENSITIVITY

A population sensitivity case assesses the impact of population assumptions. The base case year 2045 population is uniformly increased by 30 percent in all spatial elements of the 50-mile radius. This change has a significant impact on the dose risk and cost risk, increasing dose risk and cost risk by 30 percent and 29 percent, respectively. This sensitivity case demonstrates a significant dependence upon population estimates. This dependence is expected given that population dose and offsite economic costs are primarily driven by the regional population.

F.7.3.5 RESETTLEMENT PLANNING SENSITIVITIES

The MACCS2 consequence modeling incorporates an “intermediate phase” which depicts the time period following the release and immediate evacuation actions (termed the “early phase”) and extends to the time when recovery efforts such as decontamination and resettlement of people are begun (termed the “long term phase”).

The intermediate phase thus models the time period when decontamination and resettlement plans are being developed. MACCS2 allows the habitation of land during the intermediate phase unless projected dose criteria is exceeded, in which case individuals are relocated. MACCS2 allows an intermediate phase ranging from no intermediate phase to one year. The intermediate phase sensitivities show significant impacts and are therefore discussed further:

- The no intermediate phase resettlement planning case is developed based on the NUREG-1150 modeling approach. The 32 percent reduction in cost risk seen in the sensitivity results, however, is judged too optimistic in that the land decontamination efforts are modeled as starting one week after the accident (i.e., directly after the early phase ends) such that a significant portion of population relocation costs are omitted. For instance, the costs associated with temporary housing of interdicted individuals while decontamination strategies are developed and decontamination teams are contracted are not accounted for without an intermediate phase. A competing factor is that the population dose increases (10 percent increase over the base case) because people are allowed to re-occupy the land sooner. It is believed that the NUREG-1150 studies omitted the intermediate phase because the intermediate phase coding was not validated at that time (Reference 22).
- The 1 year intermediate phase resettlement planning case is developed based on the maximum length of time allowed by MACCS2 for the intermediate phase. A long intermediate phase can be unrealistic in that re-occupation of contaminated land is not performed during this phase even if contamination levels decrease (by natural radioactive decay) to levels which would allow it (i.e., resettlement is evaluated as part of the long term phase, not the intermediate phase). Therefore population relocation costs may be over estimated using a long (i.e., one year) intermediate phase. An intermediate phase of one year shows a 30 percent increase in cost risk estimates compared with the base case selection of 6 months. The population dose decreased by 6 percent with a longer intermediate phase due to later resettlement on decontaminated.
- The six month intermediate phase (base case) is judged to be a best estimate approach in that it provides reasonable time for both decontamination and resettlement planning to be performed. The sensitivity cases demonstrate that the six month value used in the base case provides mid-range results for the modeling choices available.

F.7.3.6 GENERIC ECONOMIC INPUTS SENSITIVITY

In addition to site specific values developed and used as economic inputs to the DCPP analysis (e.g., property value of farm and non-farm land), generic economic data are utilized to address costs associated with per diem living expenses (applied to owners of interdicted and relocated populations), relocation costs (for owners of interdicted properties), and decontamination costs. These generic based inputs were increased by a factor of 2.0 to assess impacts on results as follow:

DCPP MACCS2 GENERIC Economic Parameter SENSITIVITY

Variable	Description	BASE CASE Value	SENSITITY Value
EVACST[1]	Daily cost for a person who has been evacuated ($/person-day)	54.00	108.00
POPCST[1]	Population relocation cost ($/person)	10,000	20,000
RELCST[1]	Daily cost for a person who is relocated ($/person-day)	54.00	108.00
CDFRM0[1,3]	Cost of farm decontamination for two levels of decontamination ($/hectare)	1,125 2,500	2,250 5,000
CDNFRM[1,3]	Cost of non-farm decontamination per resident person for two levels of decontamination ($/person)	6,000 16,000	12,000 32,000
TIMDEC[2]	Decontamination time for each level of decontamination.[3]	2 months 4 months	2 months 12 months
TFWKNF[2]	Time workers spend in contaminated areas	1/3	1/4
DLBCST[1]	Average cost of decontamination labor ($/man-year)	70,000	140,000

(1) Base case parameters use the NUREG/CR-4551 values (Reference 20), updated to August 2008 using the consumer price index. Sensitivity case values increased by a factor of 2.

(2) Base case values based on NUREG/CR-4551. Sensitivity case values adjusted based on judgment to reflect more effort required for significant decontamination, but with less time associated with workers on the field.

(3) Two decontamination levels are modeled. The first value is associated with a dose reduction factor of 3. The second value is associated with a dose reduction factor of 15.

The increase in these generic based parameters resulted in an increase in cost risk of 45 percent and a decrease in dose risk of 2 percent. A significant increase in cost risk is expected since population relocation and decontamination costs are major contributors to total costs as calculated by MACCS2. A doubling of the economic cost risk due to a doubling of the generic cost inputs would not be expected since other site specific costs (e.g., property value of farm and non-farm land in the region) are also important contributors to the economic cost risk results and were retained at their base case values.

F.7.3.7 RATE OF RETURN SENSITIVITIES

One of the economic cost components included in the MACCS2 calculated cost result is the financial loss associated with property and associated improvements (e.g., buildings) not achieving their expected annual rate of return during interdiction periods. A piece of land that is interdicted (i.e., not occupied) for a period of years will not achieve the historical rate of return or the rate of return achieved by other non-impacted properties during the interdiction period. This lack of expected return is an economic loss for the owner / society. The base case assumes a 7 percent expected rate of return, consistent with NRC guidance (Reference 25). A sensitivity case using a 3 percent expected rate of return (Reference 25) shows a decrease in the expected cost risk of approximately 8 percent. This decrease in cost risk associated with the lower rate or return is expected since there is a lower expectation associated with the land's return on investment. A sensitivity case using a 12 percent expected rate of return, the value used in NUREG-1150 MACCS2 analyses (Reference 20), shows an increase cost risk of approximately 10 percent. For both sensitivity cases the dose risk changes are minor (about 1 percent).

F.7.3.8 IMPACT ON SAMA ANALYSIS

Several different Level 3 input parameters are examined as part of the DCPP MACCS2 sensitivity analysis. The primary reason for performing these sensitivity runs is to identify any reasonable changes that could be made to the Level 3 input parameters that would impact the conclusions of the SAMA analysis. While the table in Section F.7.3 summarizes the changes to the dose-risk and OECR estimates for each sensitivity case, it is prudent to consider if any of these changes would result in the retention of the SAMAs that were screened using the baseline results.

Of all the MACCS2 sensitivity cases, the largest dose-risk increase, 30 percent, occurred in the Population (Year 2045 population uniformly increased 30 percent) case. The largest OECR increase, 45 percent, occurred in the Generic Economic Input sensitivity case. Subsequently, the DCPP MMACR was recalculated using these results to determine the impact of using the worst case for each parameter simultaneously. The resulting MMACR is a factor of 1.31 greater than the base case, which is significantly less than the average factor of 2.36 calculated in Section F.7.2 for the 95th percentile individual SAMA PRA model results. Therefore, the 95th percentile PRA results sensitivity is considered to bound this case and no SAMAs would be retained based on this sensitivity that were not already identified in Section F.7.2.

F.8 CONCLUSIONS

The benefits of revising the operational strategies in place at DCPP and/or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. However, use of the PRA in conjunction with cost-benefit analysis methodologies provides an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on a larger future population. The results of this study indicate that several potential improvements were identified that warrant further review for potential implementation at DCPP.

In summary, based on the given implementation costs, a number of SAMAs have been identified as cost-beneficial at the 95th percentile and are suggested for potential implementation at DCPP. While these results are believed to accurately reflect potential areas for improvement at the plant, PG&E notes that this analysis should not necessarily be considered a formal disposition of these proposed changes as other engineering reviews are necessary to determine the ultimate resolution. For the identified cost-beneficial SAMAs listed below, PG&E will disposition them using existing action-tracking and design change processes.

With regard to SAMAs 12 and 13, DCPP will disposition these SAMAs based on the results of detailed fire modeling and risk analysis of the Cable Spreading Room, which will be performed as part of the NFPA 805 transition process. Insights from the detailed fire and risk modeling of the Cable Spreading Room will provide answers to the following questions: 1) Are the scenarios considered in SAMAs 12 and/or 13 indeed valid, and 2) If considered valid scenarios, are they risk significant enough to justify the cost of the proposed SAMA modification, or do other cost effective alternatives exist?

- SAMA 12: Improve Fire Barriers for ASW and CCW Equipment in the Cable Spreading Room
- SAMA 13: Improve Cable Wrap for the PORVs in the Cable Spreading Room
- SAMA 24: Prevent Clearing of RCS Cold Leg Water Seals
- SAMA 25: Fill or Maintain Filled The Steam Generators to Scrub Fission Products

F.9 TABLES

Table F.2-1
Definition of the Plant Damage State Matrix

TABLE SECTION	PARAMETER	RATIONALE FOR CATEGORY SELECTION	CODE	WHEN APPLICABLE	BINNING LOGIC (CORE DAMAGE SEQUENCES ONLY)
1	RCS PRESSURE	PRESSURE INSIDE THE RCS AT TIME OF VESSEL MELT-THROUGH IS IMPORTANT BECAUSE HIGH PRESSURE CAN EJECT MOLTEN DEBRIS THROUGH PENETRATIONS IN THE BOTTOM HEAD OF THE REACTOR VESSEL. IF PRESSURE EXCEEDS APPROXIMATELY 200 PSIA, POTENTIAL FOR EJECTION OF DISPERSED CORE DEBRIS TO CONTAINMENT EXISTS. THIS INCREASES CONTAINMENT LOADING AT TIME OF VESSEL FAILURE. PRESSURE OF 650 PSIA REPRESENTS APPROXIMATE ACCUMULATOR PRESSURE. PRESSURE OF 2250 PSIA REPRESENTS THE NORMAL OPERATING PRESSURE. ABOVE THIS PRESSURE, THE PORV SETPOINT CAN BE REACHED.	L = LOW (<200 PSIA)	FOR LARGE OR EXCESSIVE LOCA INITIATING EVENTS OR WHERE VESSEL INTEGRITY FAILS	<u>FOR GENTRN, ATWT, SGTR, MLOCA, LLOCA, ELOCA TREES</u> RCSPL:= INIT=LLOCA + INIT=ELOCA + VI=F (NO VI TOP EVENT FOR ATWT TREE) <u>FOR ISLOCA TREES</u> RCSPL:= SM=F
			I = INTERMEDIATE (200-650PSIA)	FOR SMALL LOCA'S (INCLUDING TRANSIENT INDUCED) WITH SG COOLING & HIGH PRESSURE INJECTION. FOR MEDIUM LOCAS.	SGCOOL:= AW=S <u>FOR GENTRN TREE</u> RCSPI:= (PR=F + SE=F)*SGCOOL*(CH=S + SI=S) <u>FOR ATWT TREE</u> PO=F*SGCOOL*(CH=S+SI=S)*(RS=S+ DE=S) <u>FOR SGTR TREE</u> RCSPI:= (PR=F+SE=F+SL=F+SL=B+OP=F)*SGCOOL* (CH=S+ SI=S) <u>FOR LLOCA, ELOCA TREES</u> RCSPI:= CI=S*CI=F (DOESN'T EXIST) <u>FOR ISLOCA TREE</u> RCSPI:= SM=S*SGCOOL*(CH=S + SI=S) <u>FOR MLOCA TREE</u> RCSPI:= INIT=MLOCA * VI=S
			H = HIGH (650 - 2250 PSIA)	FOR EVENTS WHERE HOT STANDBY FAILS; OR FOR SMALL LOCA'S (INCLUDING TRANSIENT INDUCED) WHERE SG COOLING FAILS AND HIGH PRESSURE ECCS INJECTION IS SUCCESSFUL; OR FOR SAMLL LOCA'S (INCLUDING TRANSIENT INDUCED) WHERE SG COOLING IS SUCCESSFUL AND HIGH PRESSURE ECCS INJECTION FAILS.	<u>FOR GENTRN,ATWT TREES</u> RCSPH:= (PR=F+SE=F) * -SGCOOL * (CH=S + SI=S) + (PR=F+SE=F) * SGCOOL * -(CH=S + SI=S) + -(RCSPL + RCSPI + RCSPS) <u>FOR SGTR TREES</u> RCSPH:= (PR=F+SE=F+SL=F+SL=B+OP=F) * -SGCOOL * (CH=S+SI=S) + (PR=F+SE=F+SL=F+SL=B+OP=F) * SGCOOL * -(CH=S+SI=S) <u>FOR MLOCA, LLOCA, ELOCA TREES</u> RCSPH:= CI=S*CI=F (DOESN'T EXIST) <u>FOR ISLOCA</u> RCSPH:= SM=S* -SGCOOL * (CH=S + SI=S) + SM=S*SGCOOL * -(CH=S + SI=S)

Table F.2-1
Definition of the Plant Damage State Matrix

TABLE SECTION	PARAMETER	RATIONALE FOR CATEGORY SELECTION	CODE	WHEN APPLICABLE	BINNING LOGIC (CORE DAMAGE SEQUENCES ONLY)
			S = PORV SETPOINT (> 2250 PSIA)	FOR ATWT CASES; OR FOR CASES WHERE PRESSURE RELIEF IS SUCCESSFUL, SG COOLING FAILS, AND BLEED AND FEED FAILS.	FOR GENTRN TREE RCSPS:= RT=F + -PR=F*-SGCOOL * (OB=F + CH=F) FOR ATWT TREE (PO=S+PR=F) * -SGCOOL * CH=F + RS=F + OE=F FOR SGTR TREES RCSPS:= CI=S*CI=F (DOESN'T EXIST) FOR MLOCA, LLOCA, AND ELOCA TREES RCSPS:= CI=S*CI=F (DOESN'T EXIST) FOR ISLOCA TREE RCSPS:= MU=F*MU=S (DOESN'T EXIST)
2	STEAM GENERATOR COOLING	AVAILABILITY OF STEAM GENERATOR SECONDARY SIDE COOLING WILL DETERMINE WHETHER THE STEAM GENERATOR TUBES WILL BE SUBJECT TO HIGH TEMPERATURES AND POTENTIAL FAILURE, IF COMBINE WITH HIGH RCS PRESSURE.	A = AVAILABLE	WHEN AFW IS AVAILABLE	SGCOOL:= AW=S FOR GENTRN, ATWT, SGTR, ISLOCA TREES SGA:= SGCOOL FOR MLOCA, LLOCA, ELOCA SGA:= SGCOOL*-SGCOOL (DOESN'T EXIST)
			X = NOT AVAILABLE	WHEN AFW IS UNAVAILABLE	FOR GENTRN, ATWT, SGTR, ISLOCA TREES SGX:= -SGCOOL FOR MLOCA, LLOCA, ELOCA SGX:= SGCOOL*-SGCOOL (DOESN'T EXIST)
			N = NOT APPLICABLE	FOR LOW PRESSURE CONDITIONS	FOR GENTRN, ATWT, SGTR, ISLOCA TREES SGN:= SGCOOL*-SGCOOL (DOESN'T EXIST) FOR MLOCA, LLOCA, ELOCA TREES SGN:= INIT=MLOCA + INIT=LLOCA + INIT=ELOCA
3	RWST INJECTED	IT IS ASSUMED THAT WATER IS PRESENT IN THE REACTOR CAVITY IF THE RWST IS INJECTED. PRESENCE OF WATER IN REACTOR CAVITY AT TIME OF MELT-THROUGH IS IMPORTANT TO CONTAINMENT RESPONSE BECAUSE INTERACTION OF WATER WITH HOT CORE DEBRIS CAN • FRAGMENT AND DISPERSE THE CORE DEBRIS FROM THEE	Y = YES	CASES WHERE RWST IS SUCCESSFUL AND ECCS INJECTION IS SUCCESSFUL.	FOR GENTRN, ATWT, MLOCA, LLOCA, ELOCA TREES RWY:= RW=S * (CH=S + SI=S + (LA=S + LB=S) * LV=S + CSI*(FC=F + VI=F + INIT=ELOCA)) FOR ISLOCA TREES RWY:= RW=S * (CH=S + SI=S) (THIS PLANT DAMAGE STATE DOES NOT EXIST) FOR SGTR TREES RWY:= RW=S * (CH=S + SI=S + (LA=S + LB=S) * LV=S + CSI*(FC=F + VI=F)) * SL=S * OP=S

Table F.2-1
Definition of the Plant Damage State Matrix

TABLE SECTION	PARAMETER	RATIONALE FOR CATEGORY SELECTION	CODE	WHEN APPLICABLE	BINNING LOGIC (CORE DAMAGE SEQUENCES ONLY)
		REACTOR CAVITY INTO OTHER REGIONS OF THE CONTAINMENT • CAUSE THE CONTAINMENT PRESSURE TO INCREASE BY VAPORIZATION OF THE WATER (I.E. STEAM SPIKES) AND DIRECT HEATING OF CONTAINMENT ATMOSPHERE (I.E. DIRECT CONTAINMENT HEATING) • ENHANCE RELEASE OF FISSION PRODUCTS FROM THE CORE DEBRIS DUE TO OXIDATION OF THE PARTICULATES.	N = NO	CASES WHERE RWST OR ASSOCIATED VALVES FAIL; OR ECCS INJECTION FAILS; OR FOR ISLOCAS.	<u>FOR GENTRN, ATWT, SGTR, MLOCA, LOCA, ELOCA TREES</u> RWN:= -RWY <u>FOR ISLOCA TREES</u> RWN:= -RWY
4	CONTAINMENT SPRAY AND HEAT REMOVAL	STATUS OF CONTAINMENT SPRAY AND CONTAINMENT HEAT REMOVAL SYSTEMS ARE IMPORTANT BECAUSE THESE CAN PROVIDE HEAT REMOVAL FOR COOLING THE CONTAINMENT ATMOSPHERE; CONTROL PRESSURE IN THE CONTAINMENT; AND PROVIDE FISSION PRODUCT REMOVAL BEFORE AND AFTER FAILURE OF THE REACTOR VESSEL. CSI INCLUDES CASES WHERE CONTAINMENT SPRAY IS OPERATING AND CASES IN WHICH CONTAINMENT SPARY WOULD OPERATE IF DEMANDED (SUPPORT AVAILABLE AND PUMPS COULD OPERATE). CSR HAS SIMILAR DEFINITION.	A = ALL SYSTEMS AVAILABLE (CSI, CSR, AND CHR)	CASES WHERE CONTAINMENT SPRAY INJECTION, CONTAINMENT SPRAY RECIRCULATION, AND CONTAINMENT HEAT REMOVAL ARE AVAILABLE. CSI INCLUDES CS OPERATING AND CS AVAILABLE (BUT NOT REQUIRED TO OPERATE PRIOR TO CORE MELT). IT WOULD IN THAT CASE BE AVAILABLE AFTER CORE MELT.	CSI:= CS=S CSI:= CS=S*(FC=F + VI=F) FOR GT CSR:= WL=S * RF=S * (VA=S*LA=S + VB=S*LB=S) * RC=S * SR=S CHR:= FC=S + CSR <u>FOR GENTRN, ATWT, SGTR, MLOCA, LLOCA, ELOCA TREES</u> CNSPA:= CSI * CSR * CHR <u>FOR ISLOCA TREES</u> CNSPA:= CSI * -CSI (DOESN'T EXIST)
			B = ALL SPRAY SYSTEMS AVAILABLE (CSI,CSR); NO CONTAINMENT HEAT REMOVAL (CHR)	CASES WHERE ALL SPRAY SYSTEMS AVAILABLE; NO CONTAINMENT HEAT REMOVAL	<u>FOR GENTRN, ATWT, SGTR, MLOCA, LLOCA, ELOCA TREES</u> CNSPB:= CSI * CSR * - CHR <u>FOR ISLOCA TREES</u> CNSPB:= CSI * -CSI (DOESN'T EXIST)
			C = SPRAY INJECTION (CSI) AND CONTAINMENT HEAT REMOVAL (CHR) AVAILABLE; SPRAY RECIRCULATION (CSR) UNAVAILABLE	CASES WHERE CONTAINMENT SPRAY INJECTION AND CONTAINMENT HEAT REMOVAL AVAILABLE; SPRAY RECIRCULATION UNAVAILABLE	<u>FOR GENTRN, ATWT, SGTR, MLOCA, LLOCA, ELOCA TREES</u> CNSPC:= CSI * -CSR * CHR <u>FOR ISLOCA TREES</u> CNSPC:= CSI * -CSI (DOESN'T EXIST)

Table F.2-1
Definition of the Plant Damage State Matrix

TABLE SECTION	PARAMETER	RATIONALE FOR CATEGORY SELECTION	CODE	WHEN APPLICABLE	BINNING LOGIC (CORE DAMAGE SEQUENCES ONLY)
			D = SPRAY INJECTION (CSI) AVAILABLE; SPRAY RECIRCULATION (CSR) AND CONTAINMENT HEAT REMOVAL (CHR) UNAVAILABLE	CASES WHERE CONTAINMENT SPRAY INJECTION AVAILABLE; CONTAINMENT SPRAY RECIRCULATION AND CONTAINMENT HEAT REMOVAL UNAVAILABLE	FOR GENTRN, ATWT, SGTR, MLOCA, LLOCA, ELOCA TREES CNSPD:= CSI * -CSR * -CHR FOR ISLOCA TREES CNSPD:= CSI * -CSI (DOESN'T EXIST)
			E = SPRAY INJECTION (CSI) UNAVAILABLE; SPRAY RECIRCULATION (CSR) AND CONTAINMENT HEAT REMOVAL (CHR) AVAILABLE	CASES WHERE CONTAINMENT SPRAY INJECTION UNAVAILABLE; CONTAINMENT SPRAY RECIRCULATION AND CONTAINMENT HEAT REMOVAL AVAILABLE. ACCORDING TO DEFINITION OF CSI AND CSR, THIS MACRO IS IMPOSSIBLE.	FOR GENTRN, ATWT, SGTR, MLOCA, LLOCA ELOCA TREES CNSPE:= -CSI * CSR * CHR FOR ISLOCA TREES CNSPE:= CSI * -CSI (DOESN'T EXIST)
			F = SPRAY INJECTION (CSI) AND CONTAINMENT HEAT REMOVAL (CHR) UNAVAILABLE; SPRAY RECIRCULATION (CSR) AVAILABLE	CONTAINMENT SPRAY INJECTION AND CONTAINMENT HEAT REMOVAL UNAVAILABLE; CONTAINMENT SPRAY RECIRCULATION AVAILABLE	FOR GENTRN, ATWT, SGTR, MLOCA, LLOCA, ELOCA TREES CNSPF:= -CSI * CSR * -CHR FOR ISLOCA TREES CNSPF:= CSI * -CSI (DOESN'T EXIST)
			G = SPRAY INJECTION AND RECIRCULATION (CSI AND CSR) UNAVAILABLE; CONTAINMENT HEAT REMOVAL (CHR) AVAILABLE	CONTAINMENT SPRAY INJECTION AND CONTAINMENT SPRAY RECIRCULATION UNAVAILABE; CONTAINMENT HEAT REMOVAL AVAILABLE	FOR GENTRN, ATWT, SGTR, MLOCA, LLOCA, ELOCA TREES CNSPG:= -CSI * -CSR * CHR + -CSI*RW=F (FAN COOLER FIX) FOR ISLOCA TREES CNSPG:= CSI * -CSI (DOESN'T EXIST)

Table F.2-1
Definition of the Plant Damage State Matrix

TABLE SECTION	PARAMETER	RATIONALE FOR CATEGORY SELECTION	CODE	WHEN APPLICABLE	BINNING LOGIC (CORE DAMAGE SEQUENCES ONLY)
			N = ALL CONTAINMENT SPRAY AND HEAT REMOVAL SYSTEMS ARE UNAVAILABLE	ALL CONTAINMENT SPRAY AND HEAT REMOVAL SYSTEMS UNAVAILABLE	FOR GENTRN, ATWT, SGTR, MLOCA, LLOCA, ELOCA TREES CNSPN:= -CSI * -CSR * -CHR FOR ISLOCA TREES CNSPN:= CSI * -CSI (DOESN'T EXIST)
5	CONTAINMENT INTEGRITY AT TIME OF VESSEL MELT-THROUGH	THE STATE OF THE CONTAINMENT ITSELF (INTACT OR FAILED) AT TIME WHEN SEVERE CORE DAMAGE STARTS INCLUDES CONTAINMENT ISOLATION FAILURE AND INTERFACING SYSTEM LOCA CONSIDERATIONS. ALSO EXTERNAL EVENTS THAT CAN CAUSE CONTAINMENT FAILURE SUCH AS EARTHQUAKES, SEVERE STORMS, OR EXTERNAL MISSILES ARE OF IMPORTANCE AT TIME OF CORE DAMAGE. THERE IS POTENTIAL FOR FILTRATION AND/OR OTHER MECHANISMS FOR FISSION PRODUCT REMOVAL IN CONTAINMENT LEAKAGE PATH (SUCH AS AUXILIARY BUILDING FILTERS FOR INTERFACING SYSTEMS LOCA'S OR PURGE FILTERS FOR SEQUENCES INVOLVING ISOLATION FAILURE) IF CONTAINMENT IS FAILED AT TIME OF CORE DAMAGE.	I = CONTAINMENT ISOLATED AND NOT BYPASSED	CASES (NON-ISLOCA AND NON-SGTR) WITH CONTAINMENT ISOLATION	FOR GENTRN, LLOCA, ELOCA TREES CNTINTI:= WL=S * CP=S * CI=S + (WL=F + CP=F + CI=F) * OI=S FOR MLOCA TREES CNTINTI:= WL=S * CP=S * CI=S + (WL=F + CP=F + CI=F) * OI=F + CORMLT * CP=B * VI=F FOR SGTR TREES CNTINTI:= (WL=S * CP=S * CI=S + (WL=F + CP=F + CI=F) * OI=S) * NI=S FOR ISLOCA TREES CNTINTI:= MU=F*MU=S (DOESN'T EXIST)
			S = SMALL LEAK (<3 INCHES DIAMETER)	CASES (NON-ISLOCA AND NON-SGTR) WITH A LEAK < 3 INCHES DIAMETER	FOR GENTRN, ELOCA TREES CNTINTS:= CP=S * (WL=F + CI=F) * OI=F FOR SGTR TREES CNTINTS:= (CP=S * (WL=F + CI=F) * OI=F) * NI=S FOR ISLOCA TREES CNTINTS:= MU=F*MU=S (DOESN'T EXIST) FOR MLOCA, LLOCA CNTINTS:= CP=S * CI=F * OI=F + CP=S * WL=F
			L = LARGE LEAK (>3 INCHES DIAMETER)	CASES (NON-ISLOCA AND NON-SGTR) WITH A LEAK > 3 INCHES DIAMETER	FOR GENTRN, LLOCA, MLOCA, ELOCA TREES CNTINTL:= CP=F * OI=F FOR SGTR TREES CNTINTL:= (CP=F * OI=F) * NI=S FOR ISLOCA TREES CNTINTL:= MU=F*MU=S (DOESN'T EXIST)
			B = SMALL BYPASS	UNISOLATED SGTR'S	FOR GENTRN, LLOCA, MLOCA, ELOCA TREES CNTINTB:= CP=F * CP=S (DOESN'T EXIST) FOR SGTR TREES CNTINTB:= NI=F FOR ISLOCA TREES CNTINTB:= MU=F * MU=S (DOESN'T EXIST)

Table F.2-1
Definition of the Plant Damage State Matrix

TABLE SECTION	PARAMETER	RATIONALE FOR CATEGORY SELECTION	CODE	WHEN APPLICABLE	BINNING LOGIC (CORE DAMAGE SEQUENCES ONLY)
			V = LARGE BYPASS	V SEQUENCE ISLOCA	FOR GENTRN, LLOCA, MLOCA, ELOCA, SGTR TREES CNTINTV:= CP=F * CP=S (DOESN'T EXIST) FOR ISLOCA TREES CNTINTV:= INIT=VDI + INIT=VSI

Table F.2-2
Plant Damage State Matrix

RCS CONDITIONS		WATER IN CONT. PRIOR TO VESSEL BREACH (3)	CONT. SPRAY & CHR (4)	CONTAINMENT ISOLATION AND BYPASS STATUS (5)																															
EXPECTED RCS PRESSURE AT ONSET OF CORE DAMAGE (1)	STEAM GEN COOLING (2)			CONTAINMENT ISOLATED AND NOT BYPASSED (I)								CONTAINMENT NOT ISOLATED OR FAILED												CONTAINMENT BYPASSED											
												LEAK < 3 IN. DIAMETER (S)								LEAK > 3 IN. DIAMETER (L)				SMALL BYPASS (B)								LARGE BYPASS (V)			
			SPRAYS OPER.	CSI & CSR		CSI ONLY		CSR ONLY		NONE		CSI & CSR		CSI ONLY		CSR ONLY		NONE		CSI & CSR	CSI ONLY	CSR ONLY	NONE	CSI & CSR		CSI ONLY		CSR ONLY		NONE		CSI & CSR	CSI ONLY	CSR ONLY	NONE
			CHR	YES	NO	YES	NO	YES	NO	YES	NO	YES	NO	YES	NO	YES	NO	YES	NO	-	-	-	-	YES	NO	YES	NO	YES	NO	YES	NO				-
				(A)	(B)	(C)	(D)	(E)	(F)	(G)	(N)	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(N)	(A)	(C)	(E)	(N)	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(N)	(A)	(C}	(E)	(N)
< 200 PSIA (L)	(N)	NO (N)		1	1,2	1	1	1,6	1,6			1	1,2	1	1	1,6	1,6			1	1	1,6		1	1,2	1	1	1,6	1,6			1,3	1,3	1,3	
		YES (Y)			2			6	6				2			6	6					6			2			6	6			3	3	3	4
200 TO 600 PSIA (I)	(N)	NO (N)		1	1,2	1	1	1,6	1,6			1	1,2	1	1	1,6	1,6			1	1	1,6		1	1,2	1	1	1,6	1,6			1,3	1,3	1,3	
		YES (Y)			2			6	6				2			6	6					6			2			6	6			3	3	3	4
600 TO 2000 PSIA (H)	YES (A)	NO (N)		1	1,2	1	1	1,6	1,6			1	1,2	1	1	1,6	1,6			1	1	1,6		1	1,2	1	1	1,6	1,6			1,3	1,3	1,3	
		YES (Y)			2			6	6				2			6	6					6			2			6	6			3	3	3	4
	NO (X)	NO (N)		1	1,2	1	1	1,6	1,6			1	1,2	1	1	1,6	1,6			1	1	1,6		1	1,2	1	1	1,6	1,6			1,3	1,3	1,3	
		YES (Y)			2			6	6				2			6	6					6			2			6	6			3	3	3	4,5
> 2000 PSIA (S)	YES (A)	NO (N)		1	1,2	1	1	1,6	1,6			1	1,2	1	1	1,6	1,6			1	1	1,6		1	1,2	1	1	1,6	1,6			1,3	1,3	1,3	5
		YES (Y)			2			6	6				2			6	6					6			2			6	6			3	3	3	4,5
	NO (X)	NO (N)		1	1,2	1	1	1,6	1,6			1	1,2	1	1	1,6	1,6			1	1	1,6		1	1,2	1	1	1,6	1,6			1,3	1,3	1,3	5
		YES (Y)			2			6	6				2			6	6					6			2			6	6			3	3	3	4,5

PDS MATRIX NOTES
1. IF RWST HAS FAILED, CSI AND CSR ARE IMPOSSIBLE.
2. CONTAINMENT HEAT REMOVAL IS GUARANTEED IF CSR IS SUCCESSFUL (REQUIRES MAAP CONFIRMATION).
3. CONTAINMENT SPRAY WILL NOT BE INITIATED FOR LARGE CONTAINMENT BYPASS EVENTS.
4. WON'T HAVE WATER IN REACTOR CAVITY FOR LARGE CONTAINMENT BYPASS EVENTS.
5. LARGE BYPASS WILL PREVENT RCS PRESSURE GREATER THAN 600 PSIA (REQUIRES MAAP CONFIRMATION).
6. CSR ONLY IMPOSSIBLE - (E & F IMPOSSIBLE).

Table F.2-3
DCPP Key Plant Damage States

	PDS	Cum	Cum %	Key Plant Damage State IDs															
PDS	Freq.	Freq.	of CDF	HAYDI	SXYAI	INYCI	LNYAI	HANNI	SXNNS	HANNS	SXNNI	INNGB	INNNS	LNYCI	SXYCI	SXYGS	SXYDI	INNGV	SXNNL
HAYDI	4.79E-05	4.79E-05	5.45E+01	4.79E-05															
SXYAI	8.96E-06	5.68E-05	6.47E+01		8.96E-06														
INYCI	6.78E-06	6.36E-05	7.24E+01			6.78E-06													
LNYAI	3.98E-06	6.76E-05	7.69E+01				3.98E-06												
HANNI	3.74E-06	7.13E-05	8.11E+01					3.74E-06											
SXNNS	3.67E-06	7.50E-05	8.53E+01						3.67E-06										
HANNS	2.06E-06	7.71E-05	8.77E+01							2.06E-06									
SXNNI	1.15E-06	7.82E-05	8.90E+01								1.15E-06								
INNGB	1.09E-06	7.93E-05	9.02E+01									1.09E-06							
INNNS	1.07E-06	8.04E-05	9.14E+01										1.07E-06						
LNYCI	1.06E-06	8.14E-05	9.26E+01											1.06E-06					
SXYCI	7.53E-07	8.22E-05	9.35E+01												7.53E-07				
HXYAI	6.68E-07	8.29E-05	9.42E+01		6.68E-07														
SXYGS	6.58E-07	8.35E-05	9.50E+01													6.58E-07			
SXYDI	5.40E-07	8.41E-05	9.56E+01														5.40E-07		
LNNNS	4.75E-07	8.45E-05	9.61E+01						4.75E-07										
HXYCI	3.93E-07	8.49E-05	9.66E+01												3.93E-07				
HXNNS	3.64E-07	8.53E-05	9.70E+01						3.64E-07										
HAYAI	3.16E-07	8.56E-05	9.74E+01		3.16E-07														
INYGS	2.74E-07	8.59E-05	9.77E+01													2.74E-07			
LNYGI	2.70E-07	8.62E-05	9.80E+01														2.70E-07		
HAYDS	2.64E-07	8.64E-05	9.83E+01							2.64E-07									
INNNB	2.04E-07	8.66E-05	9.85E+01									2.04E-07							
SXNGI	1.95E-07	8.68E-05	9.87E+01								1.95E-07								
HANGI	1.84E-07	8.70E-05	9.89E+01					1.84E-07											
SXYGI	1.23E-07	8.71E-05	9.91E+01														1.23E-07		
INNGV	8.16E-08	8.72E-05	9.92E+01															8.16E-08	
INYCS	7.96E-08	8.73E-05	9.93E+01													7.96E-08			
HAYCI	6.50E-08	8.73E-05	9.93E+01	6.50E-08															
INYGI	6.40E-08	8.74E-05	9.94E+01								6.40E-08								

Table F.2-3
DCPP Key Plant Damage States

	PDS	Cum	Cum %	Key Plant Damage State IDs															
PDS	Freq.	Freq.	of CDF	HAYDI	SXYAI	INYCI	LNYAI	HANNI	SXNNS	HANNS	SXNNI	INNGB	INNNS	LNYCI	SXYCI	SXYGS	SXYDI	INNGV	SXNNL
INYDI	6.35E-08	8.75E-05	9.95E+01														6.35E-08		
SAYCI	6.32E-08	8.75E-05	9.96E+01												6.32E-08				
HXYDI	6.06E-08	8.76E-05	9.96E+01														6.06E-08		
HXNNI	5.43E-08	8.77E-05	9.97E+01								5.43E-08								
SXYAS	5.13E-08	8.77E-05	9.97E+01													5.13E-08			
HXNGB	2.98E-08	8.77E-05	9.98E+01															2.98E-08	
LNYDI	2.70E-08	8.78E-05	9.98E+01														2.70E-08		
LNYCS	2.49E-08	8.78E-05	9.98E+01													2.49E-08			
LNYAS	1.58E-08	8.78E-05	9.99E+01													1.58E-08			
LNNGB	1.42E-08	8.78E-05	9.99E+01									1.42E-08							
INNNI	1.42E-08	8.78E-05	9.99E+01										1.42E-08						
HXYGI	1.17E-08	8.78E-05	9.99E+01														1.17E-08		
INNNL	8.76E-09	8.79E-05	9.99E+01																8.76E-09
LNNNI	8.27E-09	8.79E-05	9.99E+01										8.27E-09						
SXNNL	7.70E-09	8.79E-05	9.99E+01																7.70E-09
HXYAS	7.35E-09	8.79E-05	9.99E+01													7.35E-09			
HXNNB	6.88E-09	8.79E-05	9.99E+01															6.88E-09	
HXNGI	5.92E-09	8.79E-05	9.99E+01								5.92E-09								
SXYNS	5.85E-09	8.79E-05	1.00E+02						5.85E-09										
HAYGI	5.61E-09	8.79E-05	1.00E+02					5.61E-09											
LNNNL	3.74E-09	8.79E-05	1.00E+02																3.74E-09
SXYCS	3.67E-09	8.79E-05	1.00E+02													3.67E-09			
HXNNL	2.99E-09	8.79E-05	1.00E+02																2.99E-09
HANNB	2.91E-09	8.79E-05	1.00E+02															2.91E-09	
SXYDS	2.68E-09	8.79E-05	1.00E+02						2.68E-09										
INYNS	2.46E-09	8.79E-05	1.00E+02						2.46E-09										
HANNV	2.07E-09	8.79E-05	1.00E+02															2.07E-09	
HAYAS	1.87E-09	8.79E-05	1.00E+02													1.87E-09			
HXYCS	1.79E-09	8.79E-05	1.00E+02													1.79E-09			
HXYGS	1.72E-09	8.79E-05	1.00E+02													1.72E-09			
REMAIN	. 7.817E-	8.80E-05	1.00E+02															7.82E-09	

Table F.2-3
DCPP Key Plant Damage States

	PDS	Cum	Cum %	Key Plant Damage State IDs															
PDS	Freq.	Freq.	of CDF	HAYDI	SXYAI	INYCI	LNYAI	HANNI	SXNNS	HANNS	SXNNI	INNGB	INNNS	LNYCI	SXYCI	SXYGS	SXYDI	INNGV	SXNNL
	9																		
SUM	8.80E-05			4.79E-05	9.94E-06	6.77E-06	3.98E-06	3.92E-06	4.52E-06	2.32E-06	1.46E-06	1.30E-06	1.09E-06	1.06E-06	1.20E-06	1.12E-06	1.09E-06	1.31E-07	2.31E-08

Table F.2-4
General Release Category Considerations for Large, Dry Containment PWRs

Issue	Discussion
Containment Bypass	Interfacing system LOCA or SGTR bypassing containment have the potential for core melt without having the containment "involved" until after vessel failure.
RCS Pressure at Vessel Failure	High RCS pressure can lead to direct containment heating and containment failure at vessel failure. Also, fission product retention in the RCS is greater for high RCS pressure.
Time of Containment Failure	In general, the earlier the containment failure, the greater the source term.
Size of Containment Failure	In general, but not always, the larger the containment failure, the greater the source term.
Containment Spray System	Sprays are an important mechanism for fission product removal from the containment atmosphere. Additionally, recirculation spray operation may provide a mechanism for containment heat removal.
Debris Coolability	After vessel failure, if the core debris cannot be cooled, heat transfer from the debris can cause chemical decomposition of the concrete. As concrete is eroded by core debris, slag and gases are added to the debris and chemical reactions occur among the compounds. Concrete offgas acts as a carrier for volatile and semi-volatile reaction products which may be radioactive thus increasing the source term as the core-concrete interaction progresses.

Table F.2-5
Containment Event Tree Bins

RELEASE CATEGORY	RCS PRESSURE			CONTAINMENT FAILURE				DEBRIS COOLABLE	SPRAYS
	HIGH	MED.	LOW	EARLY	LATE	SMALL	LARGE		
RC01	X			X			X	X	X
RC01U	X			X			X		X
RC02	X			X			X	X	
RC02U	X			X			X		
RC03		X	X	X			X	X	X
RC03U		X	X	X			X		X
RC04		X	X	X			X	X	
RC04U		X	X	X			X		
RC05	X	X			X		X	X	X
RC05U	X	X			X		X		X
RC06	X	X			X		X	X	
RC06U	X	X			X		X		
RC07			X		X		X	X	X
RC07U			X		X		X		X
RC08			X		X		X	X	
RC08U			X		X		X		
RC09	X	X			X	X		X	X
RC09U	X	X			X	X			X
RC10	X	X			X	X		X	
RC10U	X	X			X	X			
RC11			X		X	X		X	X
RC11U			X		X	X			X
RC12			X		X	X		X	
RC12U			X		X	X			
RC13	X			X		X		X	X
RC13U	X			X		X			X
RC14	X			X		X		X	

Table F.2-5
Containment Event Tree Bins

RELEASE CATEGORY	RCS PRESSURE			CONTAINMENT FAILURE				DEBRIS COOLABLE	SPRAYS
	HIGH	MED.	LOW	EARLY	LATE	SMALL	LARGE		
RC14U	X			X		X			
RC15		X	X	X		X		X	X
RC15U		X	X	X		X			X
RC16		X	X	X		X		X	
RC16U		X	X	X		X			
RC17	SGTR								
RC18	Interfacing System LOCA								
RC19	Non-Severe Core Damage Sequence								
RC20	Long Term Containment Intact Sequence								
RC21	Basemelt Melt-Through Sequence								

Table F.2-6
Fission Product Groups

Group Number	Group Name	Elements Included in Group
1	NG	Xe, Kr
2	I	I, Br
3	Cs	Cs, Rb
4	Te	Te, Sb, Se
5	Sr	Sr
6	Ru	Ru, Rh, Pd, Mo, Tc, Co
7	La	La, Zr, Nd, Eu, Nb, Pm Pr, Cm, Y
8	Ce	Ce, Pu, Np
9	Ba	Ba

Table F.2-7
ZISOR Binning Rules

Parameter	Code	Code Description
1. Containment Failure Mode	A	Containment Bypass (Not Submerged)
	B	Containment Bypass (Submerged)
	C	Containment Failure Before Vessel Failure
	D	Containment Failure at Vessel Failure (VF)
	E	Late Containment Failure (VF+6 Hr)
	F	Very Late Containment Failure (VF+24 Hr)
	G	No Containment Failure
2. Spray Operation	A	Early (To VF)
	B	Intermediate (To VF + 45 Min)
	C	Late (To End of CCI)
	D	Very Late (After CCI)
	E	From (VF + 45 Min) To (End of CCI)
	F	From (VF + 45 Min) To (After CCI)
	G	Only After CCI
	H	Non-Operational
3. Core-Concrete Interaction (CCI)	A	Prompt Dry
	B	Prompt Shallow Scrubbed
	C	No CCI
	D	Prompt Deep Scrubbed
	E	Short Delayed, thereafter Dry
	F	Long Delayed, thereafter Dry
4. RCS Pressure At Vessel Failure	A	System Setpoint
	B	High Pressure
	C	Intermediate Pressure
	D	Low Pressure
5. Mode Of Vessel Failure	A	HPME
	B	Pour

Table F.2-7
ZISOR Binning Rules

Parameter	Code	Code Description
	C	Gross Bottom Head Failure
	D	Alpha-Mode
	E	Rocket
	F	No Vessel Failure
6. SGTR	A	Occurs (SRV Closes)
	B	Occurs (SRV Remains Open)
	C	None
7. Amount Of Core in CCI	A	Large Amount (70-100 percent)
	B	Moderate Amount (30-100 percent)
	C	Small Amount (0-30 percent)
	D	None
8. Zirconium Oxidation	A	Low Zr Oxidation (0-40 percent)
	B	High Zr Oxidation (> 40 percent)
9. High Pressure Melt Ejection	A	High HPME
	B	Moderate HPME
	C	Low HPME
	D	No HPME
10. Containment Failure Size	A	Catastrophic Failure
	B	Rupture (Nominally 7 Ft2)
	C	Leak (Nominally 0.1 Ft2)
	D	No Failure
11. Holes In RCS	A	One Large Hole
	B	Two Large Hole

Table F.2-8
RELEASE CATEGORY SOURCE TERMS (Fraction of Core Inventory)

DESCRIPTION	Frequency	ZISOR Bin[1]	NG	I	Cs	Te	Sr	Ru/Mo	La	Ce	Ba
RC10 HIGH-MED RCS PRESS	1.98e-05	EHCCACDACCA	1.0e+00	4.7e-03	3.2e-03	1.6e-05	1.3e-04	1.0e-09	1.0e-10	1.0e-10	1.3e-04
SMALL-LATE CF		MAAP/HAYDI	7.5e-01	3.2e-04	3.7e-04	0.0	1.1e-08	3.9e-07	1.1e-09	2.4e-09	1.2e-07
RC12U LOW RCS PRESS	1.2e-05	EHADBCAADCA	1.0e+00	3.8e-03	3.1e-03	3.5e-02	1.0e-03	1.4e-06	4.1e-06	4.1e-06	1.0e-03
SMALL-LATE CF		MAAP/HAYDI	8.4e-01	4.9e-03	4.8e-03	1.1e-01	1.5e-04	1.6e-04	6.7e-06	9.8e-05	1.4e-04
RC21	1.1e-05	FHADBCAADBB	1.0e+00	4.8e-04	2.5e-06	1.8e-05	7.1e-06	7.3e-10	3.9e-08	3.9e-08	7.1e-06
BASEMAT MELT-THROUGH		MAAP/INYCI	7.8e-01	1.6e-04	1.7e-04	1.7e-04	4.0e-06	7.4e-05	3.5e-08	4.3e-07	1.9e-04
RC19	1.0e-05	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NON-SEVERE CORE DAMAGE		N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RC08U LOW RCS PRESS	8.1e-06	EHADBCAADBA	1.0e+00	8.5e-02	8.8e-02	1.1e-01	2.5e-02	3.6e-06	8.2e-05	8.2e-05	2.5e-02
LARGE-LATE CF		MAAP/HAYDI	1.0e+00	2.0e-02	2.3e-02	2.8e-01	9.6e-04	1.1e-03	4.4e-05	6.2e-04	1.4e-03
RC20	6.9e-06	GHCBACDABDA	5.0e-03	5.2e-07	5.1e-07	5.4e-09	4.4e-08	3.4e-13	3.4e-14	3.4e-14	4.4e-08
LONG TERM CONT. INTACT		MAAP/SXYAI	1.8e-03	1.1e-05	1.1e-05	0.0	1.8e-07	2.2e-05	1.6e-08	6.0e-07	2.0e-06
RC06 HIGH-MED RCS PRESS	6.4e-06	EHCCACDACBA	1.0e+00	5.5e-02	5.4e-02	5.4e-04	4.4e-03	3.4e-08	3.4e-09	3.4e-09	4.4e-03
LARGE-LATE CF		MAAP/HAYDI	9.9e-01	1.9e-03	3.1e-03	0.0	2.1e-08	7.1e-07	2.6e-09	5.8e-09	2.1e-07
RC14 HIGH RCS PRESS	2.6e-06	DHCBACDABCA	1.0e+00	5.1e-02	5.1e-02	7.8e-04	4.5e-03	5.3e-04	1.3e-04	1.3e-04	4.7e-03
SMALL-EARLY CF		MAAP/SXNNS	8.9e-01	1.5e-02	1.5e-02	0.0	4.2e-05	1.3e-03	4.2e-06	4.2e-06	4.3e-04
RC16U MED-LOW RCS PRESS	2.4e-06	DHADBCAADCB	1.0e+00	8.6e-02	8.9e-02	5.7e-02	2.4e-02	1.5e-06	7.7e-05	7.7e-05	2.4e-02
SMALL-EARLY CF		MAAP/SXNNS	7.7e-01	5.1e-02	4.3e-02	1.6e-01	4.3e-04	2.7e-03	2.0e-05	2.5e-04	7.8e-04
RC16 MED-LOW RCS PRESS	1.8e-06	DHCCACDACCA	1.0e+00	5.1e-02	5.1e-02	7.2e-04	4.6e-03	3.7e-04	2.0e-04	2.0e-04	4.6e-03
SMALL-EARLY CF		MAAP/HANNS	8.7e-01	1.2e-02	1.1e-02	0.0	4.1e-05	2.2e-03	1.0e-06	4.2e-06	5.3e-04

Table F.2-8
RELEASE CATEGORY SOURCE TERMS (Fraction of Core Inventory)

DESCRIPTION	Frequency	ZISOR Bin[1]	NG	I	Cs	Te	Sr	Ru/Mo	La	Ce	Ba
RC17	1.5e-06	GHCCABDACDA	1.0e+00	5.9e-01	5.6e-01	6.7e-02	4.6e-02	3.5e-07	3.5e-08	3.5e-08	4.6e-02
SGTR		MAAP/INNGB	9.4e-01	4.2e-01	4.5e-01	0.0	1.3e-03	6.2e-02	2.7e-05	1.2e-04	1.6e-02
RC10U HIGH-MED RCS PRESS	1.2e-06	EHACBCAADCA	1.0e+00	5.3e-03	3.2e-03	3.4e-02	8.5e-04	1.4e-06	4.1e-06	4.1e-06	8.5e-04
SMALL-LATE CF		MAAP/HANNI	8.3e-01	5.2e-03	4.5e-03	1.3e-01	1.7e-04	2.1e-04	6.4e-06	1.1e-04	1.3e-04
RC06U HIGH-MED RCS PRESS	1.1e-06	EHACBCAADBA	1.0e+00	5.7e-02	5.5e-02	8.5e-02	1.9e-02	3.5e-06	8.2e-05	8.2e-05	1.9e-02
LARGE-LATE CF		MAAP/HANNI	9.9e-01	4.3e-02	4.2e-02	2.9e-01	1.1e-03	1.4e-03	4.1e-05	6.9e-04	9.8e-04
RC04 MED-LOW RCS PRESS	8.7e-07	DHCCACDACBA	1.0e+00	3.9e-01	4.0e-01	5.7e-03	3.7e-02	3.0e-03	1.6e-03	1.6e-03	3.7e-02
LARGE-EARLY CF		MAAP/HAYDI	1.0e+00	9.7e-02	9.7e-02	0.0	7.2e-04	1.5e-02	1.7e-04	3.8e-04	7.8e-03
RC02 HIGH RCS PRESS	7.0e-07	DHCAACDAABA	1.0e+00	2.0e-01	1.7e-01	3.5e-02	1.3e-02	6.4e-03	1.5e-03	1.5e-03	1.4e-02
LARGE-EARLY CF		MAAP/SXNNS	9.9e-01	1.6e-01	1.4e-01	0.0	2.8e-04	1.1e-02	3.4e-05	3.4e-05	3.1e-03
RC12 LOW RCS PRESS	6.4e-07	EHCDBCDADCA	1.0e+00	3.3e-03	3.0e-03	6.6e-04	2.9e-04	2.3e-09	2.3e-10	2.3e-10	2.9e-04
SMALL-LATE CF		MAAP/HAYDI	8.4e-01	4.0e-05	5.7e-05	5.1e-07	1.3e-08	4.1e-07	9.8e-10	1.1e-09	1.4e-07
RC14U HIGH RCS PRESS	4.8e-07	DHABBCAADCA	1.0e+00	5.2e-02	5.3e-02	3.5e-02	1.8e-02	1.5e-06	7.7e-05	7.7e-05	1.8e-02
SMALL-EARLY CF		MAAP/SXNNS	9.1e-01	1.8e-02	1.7e-02	1.9e-01	3.5e-04	1.2e-03	1.9e-05	2.5e-04	5.5e-04
RC04U MED-LOW RCS PRESS	4.6e-07	DHADBCAADBA	1.0e+00	6.7e-01	6.9e-01	2.8e-01	1.2e-01	4.7e-06	2.2e-04	2.2e-04	1.2e-01
LARGE-EARLY CF		MAAP/HAYDI	9.9e-01	8.6e-02	8.6e-02	2.2e-01	3.2e-03	1.2e-02	2.6e-04	2.0e-03	7.5e-03
RC13 HIGH RCS PRESS	3.8e-07	DDCAACDAACA	1.0e+00	6.7e-04	5.3e-04	9.0e-05	3.2e-05	2.2e-10	2.2e-11	2.2e-11	3.2e-05
SMALL-EARLY CF		MAAP/SXYAI	2.3e-01	9.9e-05	7.4e-05	0.0	1.7e-07	1.2e-05	6.1e-09	9.6e-09	2.3e-06
RC01 HIGH RCS PRESS	2.4e-07	DDCAACDAABA	1.0e+00	7.0e-02	6.1e-02	1.2e-02	4.4e-03	3.1e-08	3.1e-09	3.1e-09	4.4e-03
LARGE-EARLY CF		MAAP/SXYAI	9.1e-01	1.2e-02	9.1e-03	0.0	2.0e-05	1.4e-03	7.3e-07	1.2e-06	2.8e-04

Table F.2-8
RELEASE CATEGORY SOURCE TERMS (Fraction of Core Inventory)

DESCRIPTION	Frequency	ZISOR Bin[(1)]	NG	I	Cs	Te	Sr	Ru/Mo	La	Ce	Ba
RC08 LOW RCS PRESS	1.8e-07	EHCDBCDADBA	1.0e+00	8.4e-02	8.7e-02	2.2e-02	1.0e-02	7.7e-08	7.7e-09	7.7e-09	1.0e-02
LARGE-LATE CF		MAAP/HAYDI	1.0e+00	2.0e-03	2.9e-03	3.5e-06	1.9e-08	5.7e-07	1.5e-09	1.7e-09	1.9e-07
RC18	1.3e-07	AHADBCAADDA	1.0e+00	1.7e-01	1.7e-01	1.2e-01	4.9e-02	4.2e-06	2.2e-04	2.2e-04	4.9e-02
INTERFACING SYSTEM LOCA		MAAP/INNGV	1.0e+00	5.4e-01	5.5e-01	9.0e-02	3.0e-03	4.8e-03	4.2e-04	1.4e-03	1.3e-02
RC03U MED-LOW RCS PRESS	1.2e-07	DDADBCAADBB	1.0e+00	1.5e-02	1.6e-02	7.3e-03	3.1e-03	1.5e-07	7.4e-06	7.4e-06	3.1e-03
LARGE-EARLY CF		MAAP/SXYAI	9.7e-01	1.2e-02	1.2e-02	2.0e-03	1.5e-04	4.5e-03	1.4e-05	7.9e-05	1.2e-03
RC03 MED-LOW RCS PRESS	5.8e-08	DDCDBCDADBB	1.0e+00	1.5e-02	1.5e-02	4.0e-03	1.8e-03	1.4e-08	1.4e-09	1.4e-09	1.8e-03
LARGE-EARLY CF		MAAP/SXYAI	7.3e-01	7.7e-03	7.6e-03	3.5e-09	5.3e-04	9.0e-03	8.0e-05	3.5e-03	5.7e-03

Table F.3-1
Estimated Population Distribution within a 10-Mile Radius(1) of DCPP, Year 2045

Sector	0-1 mile	1-2 miles	2-3 miles	3-4 miles	4-5 miles	5-10 miles	10-mile Total
N	0	53	34	34	39	24792	24952
NNE	0	53	34	34	50	15301	15472
NE	0	53	34	34	39	2733	2893
ENE	0	53	34	34	47	13020	13188
E	0	53	34	34	47	3262	3430
ESE	0	53	34	34	47	9192	9360
SE	0	53	0	0	0	5	58
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	0	0	0	0	0
SW	0	0	0	0	0	0	0
WSW	0	0	0	0	0	0	0
W	0	0	0	0	0	0	0
WNW	0	0	0	0	0	0	0
NW	0	53	0	0	0	0	53
NNW	0	64	34	34	39	0	171
Total	0	488	238	238	308	68305	69577

(1)Population estimate for 10-mile radius includes transients and residents.

Table F.3-2
Estimated Population Distribution within a 50-Mile Radius(1) of DCPP, Year 2045

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile Total
N	24952	26758	2914	28113	7412	90149
NNE	15472	2703	107213	104661	5518	235567
NE	2893	15457	41963	8854	6458	75625
ENE	13188	69360	1202	1938	6954	92642
E	3430	16478	595	268	4359	25130
ESE	9360	87700	20727	1937	450	120174
SE	58	7656	157013	199367	14442	378536
SSE	0	0	189	17047	146259	163495
S	0	0	0	0	0	0
SSW	0	0	0	0	0	0
SW	0	0	0	0	0	0
WSW	0	0	0	0	0	0
W	0	0	0	0	0	0
WNW	0	0	0	0	0	0
NW	53	0	0	150	67	270
NNW	171	234	9588	687	482	11162
Total	69577	226346	341404	363022	192401	1192750

(1) Population estimate for 10-mile radius includes transients and residents. Population estimate for 10 – 50 mile radius includes residents only.

Table F.3-3
DCPP MACCS2 End of Cycle Core Inventory

Entry	Nuclide	Activity (Bq)	Entry	Nuclide	Activity (Bq)
1	Co-58	2.44E+16	31	Te-131m	6.54E+17
2	Co-60	7.96E+14	32	Te-132	4.79E+18
3	Kr-85	3.44E+16	33	I-131	3.33E+18
4	Kr-85m	8.35E+17	34	I-132	4.88E+18
5	Kr-87	1.67E+18	35	I-133	6.87E+18
6	Kr-88	2.32E+18	36	I-134	7.62E+18
7	Rb-86	6.45E+15	37	I-135	6.56E+18
8	Sr-89	3.28E+18	38	Xe-133	6.88E+18
9	Sr-90	3.02E+17	39	Xe-135	1.88E+18
10	Sr-91	4.06E+18	40	Cs-134	5.64E+17
11	Sr-92	4.32E+18	41	Cs-136	1.76E+17
12	Y-90	3.23E+17	42	Cs-137	4.07E+17
13	Y-91	4.26E+18	43	Ba-139	6.08E+18
14	Y-92	4.36E+18	44	Ba-140	6.12E+18
15	Y-93	3.32E+18	45	La-140	6.33E+18
16	Zr-95	5.91E+18	46	La-141	5.54E+18
17	Zr-97	5.72E+18	47	La-142	5.42E+18
18	Nb-95	5.96E+18	48	Ce-141	5.61E+18
19	Mo-99	6.26E+18	49	Ce-143	5.19E+18
20	Tc-99m	5.55E+18	50	Ce-144	4.25E+18
21	Ru-103	5.23E+18	51	Pr-143	5.07E+18
22	Ru-105	3.59E+18	52	Nd-147	2.25E+18
23	Ru-106	1.70E+18	53	Np-239	6.53E+19
24	Rh-105	3.30E+18	54	Pu-238	1.26E+16
25	Sb-127	2.84E+17	55	Pu-239	1.15E+15
26	Sb-129	1.06E+18	56	Pu-240	1.52E+15
27	Te-127	2.79E+17	57	Pu-241	4.93E+17
28	Te-127m	4.60E+16	58	Am-241	6.48E+14
29	Te-129	1.01E+18	59	Cm-242	1.63E+17
30	Te-129m	2.05E+17	60	Cm-244	1.30E+16

Table F.3-4
MACCS2 Release Categories vs. DCPP Release Categories

MACCS2 Release Categories	DCPP Release Categories
Xe/Kr	1 – noble gases
I	2 – CsI
Cs	6 & 2 – CsOH and CsI[3]
Te	3 & 11- TeO_2, Sb[2] & Te_2 [1]
Sr	4 – SrO
Ru	5 – MoO_2 (Mo is in Ru MACCS category)
La	8 – La_2O_3
Ce	9 – CeO_2 & UO_2 [1]
Ba	7 – BaO

(1) These release fractions are typically negligible compared to others in the group.
(2) The mass of Sb in the core is typically much less than the mass of Te.
(3) The mass of Cs contained in CsI is typically much less than the mass of Cs contained in CsOH.

Table F.3-5
Representative MAAP Level 2 Case Descriptions and Key Event Timings

Source Term	Release Category	MAAP Case	Representative Case Description	CSI RF(1)	TCD (HRS)(2)	TVF (HRS)(3)	TCF (HRS)(4)	TEND (HRS)(5)
ST1	LG/EARLY	RC04U	Loss of all injection, AFW, containment sprays. Depressurize SGs at 15 min. Large (7 ft^2) containment breach at time of vessel failure.	6.01E-02	2.6	3.7	3.7	48
ST2	SM/EARLY	RC14	Loss of all injection, AFW, containment sprays. Small (.1 ft^2) containment breach at time zero.	4.57E-03	2.8	4.0	0.0	48
ST3	LATE	RC10	180 gpm/pump seal LOCA. AFW OK, CS OK. Containment failure when pressure > 150 psia.	4.05E-04	3.8	6.1	37.9	72
ST4	BYPASS w/ AFW	RC17	SGTR with loss of all injection and with AFW. SG PORV stuck open.	2.60E-02	42.1	66.5	0.0	72
ST5	ISLOCA	RC18	6" RHR pipe break, release directly to environment, no inj, w/ AFW	8.70E-01	1.1	2.5	NA	48
ST6	INTACT	RC20	MLOCA with failure to recirc. HPI OK. AFW OK. CS with heat removal OK.	3.17E-05	6.9	9.3	NA	48

Notes:

(1) CsI RF – Cesium Iodide release fraction to the environment
(2) Tcd - Time of core damage (maximum core temperature >1800°F)
(3) Tvf - Time of vessel breach
(4) Tcf – Time of containment failure
(5) Tend – Time at end of run

Table F.3-6
DCPP Source Term Summary

Release Category

	ST 1 LG/EARLY	ST 2 SM/EARLY	ST 3 LATE	ST 4 BYPASS w/ AFW	ST 5 ISLOCA	ST 6 INTACT
MAAP Case	RC04U	RC14	RC10	RC17 W AFW	RC18	RC20
Run Duration	48 hr	48 hr	72 hr	72 hr	48 hr	48 hr
Time after Scram when GE is declared (1)	2.6 hr	2.8 hr	3.8 hr	36 hr	1.1 hr	6.9 hr
Fission Product Group:						
1) Noble						
Total Release Fraction	7.60E-01	3.60E-01	9.70E-01	1.00E+00	1.00E+00	1.80E-03
Total Plume 1 Release Fraction	5.80E-01	2.20E-01	6.40E-01	8.10E-01	9.70E-01	3.00E-04
Start of Plume 1 Release (hr)	3.60	3.00	38.00	42.10	1.10	6.90
End of Plume 1 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
Total Plume 2 Release Fraction	9.00E-02	1.30E-01	2.30E-01	6.00E-02	3.00E-02	5.00E-04
Start of Plume 2 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
End of Plume 2 Release (hr)	6.00	11.00	58.00	56.00	5.00	24.00
Total Plume 3 Release Fraction	9.00E-02	1.00E-02	1.00E-01	1.30E-01	0.00E+00	1.00E-03
Start of Plume 3 Release (hr)	6.00	11.00	58.00	63.00		24.00
End of Plume 3 Release (hr)	16.00	21.00	68.00	66.00		34.00
2) CsI						
Total Release Fraction	6.00E-02	4.60E-03	4.00E-04	2.60E-02	8.70E-01	3.20E-05
Total Plume 1 Release Fraction	5.50E-02	4.20E-03	3.00E-04	2.50E-02	8.20E-01	2.80E-05
Start of Plume 1 Release (hr)	3.60	3.00	38.00	42.10	1.10	6.90
End of Plume 1 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
Total Plume 2 Release Fraction	5.00E-03	4.00E-04	7.00E-05	0.00E+00	2.00E-02	1.00E-06
Start of Plume 2 Release (hr)	4.00	7.00	48.00		2.00	14.00
End of Plume 2 Release (hr)	6.00	11.00	58.00		5.00	24.00
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	3.00E-05	1.00E-03	3.00E-02	3.00E-06
Start of Plume 3 Release (hr)			58.00	63.00	5.00	24.00
End of Plume 3 Release (hr)			68.00	66.00	15.00	34.00

Table F.3-6
DCPP Source Term Summary

Release Category

	ST 1 LG/EARLY	ST 2 SM/EARLY	ST 3 LATE	ST 4 BYPASS w/ AFW	ST 5 ISLOCA	ST 6 INTACT
MAAP Case	RC04U	RC14	RC10	RC17 W AFW	RC18	RC20
Run Duration	48 hr	48 hr	72 hr	72 hr	48 hr	48 hr
Time after Scram when GE is declared (1)	2.6 hr	2.8 hr	3.8 hr	36 hr	1.1 hr	6.9 hr
Fission Product Group:						
3) TeO_2						
Total Release Fraction	2.60E-02	2.50E-03	1.00E-04	1.30E-02	8.30E-01	2.20E-05
Total Plume 1 Release Fraction	2.50E-02	2.40E-03	9.00E-05	1.10E-02	7.90E-01	2.00E-05
Start of Plume 1 Release (hr)	3.60	3.00	38.00	42.10	1.10	6.90
End of Plume 1 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
Total Plume 2 Release Fraction	1.00E-03	1.00E-04	1.00E-05	1.00E-03	4.00E-02	2.00E-06
Start of Plume 2 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
End of Plume 2 Release (hr)	6.00	11.00	58.00	56.00	5.00	24.00
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	0.00E+00	1.00E-03	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)				63.00		
End of Plume 3 Release (hr)				66.00		
4) SrO						
Total Release Fraction	4.30E-02	5.00E-03	1.60E-05	3.50E-04	2.30E-02	7.00E-07
Total Plume 1 Release Fraction	4.20E-02	4.90E-03	1.30E-05	3.10E-04	1.40E-02	5.80E-07
Start of Plume 1 Release (hr)	3.60	3.00	38.00	42.10	1.10	6.90
End of Plume 1 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
Total Plume 2 Release Fraction	1.00E-03	1.00E-04	2.00E-06	2.00E-05	8.00E-03	1.10E-07
Start of Plume 2 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
End of Plume 2 Release (hr)	6.00	11.00	58.00	56.00	5.00	24.00
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	1.00E-06	2.00E-05	1.00E-03	1.00E-08
Start of Plume 3 Release (hr)			58.00	63.00	5.00	24.00
End of Plume 3 Release (hr)			68.00	66.00	15.00	34.00
5) MoO_2						
Total Release Fraction	4.40E-02	5.20E-03	1.80E-05	2.40E-03	3.80E-02	9.10E-06
Total Plume 1 Release Fraction	4.20E-02	5.00E-03	1.50E-05	2.20E-03	3.70E-02	7.10E-06

Table F.3-6
DCPP Source Term Summary

Release Category

	ST 1 LG/EARLY	ST 2 SM/EARLY	ST 3 LATE	ST 4 BYPASS w/ AFW	ST 5 ISLOCA	ST 6 INTACT
MAAP Case	RC04U	RC14	RC10	RC17 W AFW	RC18	RC20
Run Duration	48 hr	48 hr	72 hr	72 hr	48 hr	48 hr
Time after Scram when GE is declared (1)	2.6 hr	2.8 hr	3.8 hr	36 hr	1.1 hr	6.9 hr
Fission Product Group:						
Start of Plume 1 Release (hr)	3.60	3.00	38.00	42.10	1.10	6.90
End of Plume 1 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
Total Plume 2 Release Fraction	2.00E-03	1.00E-04	3.00E-06	2.00E-04	1.00E-03	2.00E-06
Start of Plume 2 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
End of Plume 2 Release (hr)	6.00	11.00	58.00	56.00	5.00	24.00
Total Plume 3 Release Fraction	0.00E+00	1.00E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)		11.00				
End of Plume 3 Release (hr)		21.00				
6) CsOH						
Total Release Fraction	1.50E-02	1.60E-03	1.20E-04	2.40E-02	8.50E-02	2.20E-05
Total Plume 1 Release Fraction	1.40E-02	1.50E-03	7.00E-05	2.20E-02	8.20E-01	2.10E-05
Start of Plume 1 Release (hr)	3.60	3.00	38.00	42.10	1.10	6.90
End of Plume 1 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
Total Plume 2 Release Fraction	1.00E-03	1.00E-04	2.00E-05	0.00E+00	2.00E-02	1.00E-06
Start of Plume 2 Release (hr)	4.00	7.00	48.00		2.00	14.00
End of Plume 2 Release (hr)	6.00	11.00	58.00		5.00	24.00
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	3.00E-05	2.00E-03	1.00E-02	0.00E+00
Start of Plume 3 Release (hr)			58.00	63.00	5.00	
End of Plume 3 Release (hr)			68.00	66.00	15.00	
7) BaO						
Total Release Fraction	4.30E-02	5.00E-03	1.60E-05	9.50E-04	3.70E-02	1.90E-06
Total Plume 1 Release Fraction	4.10E-02	4.90E-03	1.30E-05	8.40E-04	3.30E-02	1.50E-06
Start of Plume 1 Release (hr)	3.60	3.00	38.00	42.10	1.10	6.90
End of Plume 1 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
Total Plume 2 Release Fraction	2.00E-03	1.00E-04	3.00E-06	8.00E-05	4.00E-03	4.00E-07

Table F.3-6
DCPP Source Term Summary

Release Category

	ST 1 LG/EARLY	ST 2 SM/EARLY	ST 3 LATE	ST 4 BYPASS w/ AFW	ST 5 ISLOCA	ST 6 INTACT
MAAP Case	RC04U	RC14	RC10	RC17 W AFW	RC18	RC20
Run Duration	48 hr	48 hr	72 hr	72 hr	48 hr	48 hr
Time after Scram when GE is declared (1)	2.6 hr	2.8 hr	3.8 hr	36 hr	1.1 hr	6.9 hr
Fission Product Group:						
Start of Plume 2 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
End of Plume 2 Release (hr)	6.00	11.00	58.00	56.00	5.00	24.00
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	0.00E+00	3.00E-05	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)				63.00		
End of Plume 3 Release (hr)				66.00		
8) La2O3						
Total Release Fraction	4.30E-02	5.00E-03	1.60E-05	8.20E-06	9.10E-04	1.70E-08
Total Plume 1 Release Fraction	4.20E-02	4.90E-03	1.30E-05	5.30E-06	2.90E-04	1.40E-08
Start of Plume 1 Release (hr)	3.60	3.00	38.00	42.10	1.10	6.90
End of Plume 1 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
Total Plume 2 Release Fraction	1.00E-03	1.00E-04	2.00E-06	1.10E-06	6.00E-04	3.00E-09
Start of Plume 2 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
End of Plume 2 Release (hr)	6.00	11.00	58.00	56.00	5.00	24.00
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	1.00E-06	1.80E-06	2.00E-05	0.00E+00
Start of Plume 3 Release (hr)			58.00	63.00	5.00	
End of Plume 3 Release (hr)			68.00	66.00	15.00	
9) CeO2						
Total Release Fraction	4.30E-02	5.00E-03	1.60E-05	5.20E-05	1.00E-02	4.20E-08
Total Plume 1 Release Fraction	4.20E-02	4.90E-03	1.30E-05	4.30E-05	1.00E-03	3.70E-08
Start of Plume 1 Release (hr)	3.60	3.00	38.00	42.10	1.10	6.90
End of Plume 1 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
Total Plume 2 Release Fraction	1.00E-03	1.00E-04	2.00E-06	4.00E-06	8.00E-03	4.00E-09
Start of Plume 2 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
End of Plume 2 Release (hr)	6.00	11.00	58.00	56.00	5.00	24.00
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	1.00E-06	5.00E-06	1.00E-03	1.00E-09

Table F.3-6
DCPP Source Term Summary

Release Category

	ST 1 LG/EARLY	ST 2 SM/EARLY	ST 3 LATE	ST 4 BYPASS w/ AFW	ST 5 ISLOCA	ST 6 INTACT
MAAP Case	RC04U	RC14	RC10	RC17 W AFW	RC18	RC20
Run Duration	48 hr	48 hr	72 hr	72 hr	48 hr	48 hr
Time after Scram when GE is declared (1)	2.6 hr	2.8 hr	3.8 hr	36 hr	1.1 hr	6.9 hr
Fission Product Group:						
Start of Plume 3 Release (hr)			58.00	63.00	5.00	24.00
End of Plume 3 Release (hr)			68.00	66.00	15.00	34.00
10) Sb						
Total Release Fraction	5.20E-02	6.90E-03	3.10E-04	6.30E-03	4.50E-01	2.40E-05
Total Plume 1 Release Fraction	5.00E-02	6.60E-03	7.00E-05	5.20E-03	3.70E-01	1.70E-05
Start of Plume 1 Release (hr)	3.60	3.00	38.00	42.10	1.10	6.90
End of Plume 1 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
Total Plume 2 Release Fraction	2.00E-03	3.00E-03	9.00E-05	1.00E-04	5.00E-02	6.00E-06
Start of Plume 2 Release (hr)	4.00	7.00	48.00	46.00	2.00	14.00
End of Plume 2 Release (hr)	6.00	11.00	58.00	56.00	5.00	24.00
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	1.50E-04	1.00E-03	3.00E-02	1.00E-06
Start of Plume 3 Release (hr)			58.00	63.00	5.00	24.00
End of Plume 3 Release (hr)			68.00	66.00	15.00	34.00
11) Te2						
Total Release Fraction	1.30E-04	3.40E-05	2.20E-05	4.00E-07	9.60E-04	0.00E+00
Total Plume 1 Release Fraction	1.30E-04	3.30E-05	1.40E-05	0.00E+00	0.00E+00	0.00E+00
Start of Plume 1 Release (hr)	3.60	3.00	38.00			
End of Plume 1 Release (hr)	4.00	7.00	48.00			
Total Plume 2 Release Fraction	0.00E+00	1.00E-06	5.00E-06	0.00E+00	9.20E-04	0.00E+00
Start of Plume 2 Release (hr)		7.00	48.00		2.00	
End of Plume 2 Release (hr)		11.00	58.00		5.00	
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	3.00E-06	4.00E-07	4.00E-05	0.00E+00
Start of Plume 3 Release (hr)			58.00	63.00	5.00	
End of Plume 3 Release (hr)			68.00	66.00	15.00	

Table F.3-6
DCPP Source Term Summary

Release Category

	ST 1 LG/EARLY	ST 2 SM/EARLY	ST 3 LATE	ST 4 BYPASS w/ AFW	ST 5 ISLOCA	ST 6 INTACT
MAAP Case	RC04U	RC14	RC10	RC17 W AFW	RC18	RC20
Run Duration	48 hr	48 hr	72 hr	72 hr	48 hr	48 hr
Time after Scram when GE is declared (1)	2.6 hr	2.8 hr	3.8 hr	36 hr	1.1 hr	6.9 hr
Fission Product Group:						
12) UO2						
Total Release Fraction	3.80E-08	0.00E+00	0.00E+00	2.20E-09	5.00E-05	0.00E+00
Total Plume 1 Release Fraction	3.60E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Plume 1 Release (hr)	3.60					
End of Plume 1 Release (hr)	4.00					
Total Plume 2 Release Fraction	2.00E-09	0.00E+00	0.00E+00	0.00E+00	4.60E-05	0.00E+00
Start of Plume 2 Release (hr)	4.00				2.00	
End of Plume 2 Release (hr)	6.00				5.00	
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	0.00E+00	2.20E-09	4.00E-06	0.00E+00
Start of Plume 3 Release (hr)				63.00	5.00	
End of Plume 3 Release (hr)				66.00	15.00	

(1) General Emergency declaration estimated from Diablo Canyon Emergency Classification Guide (Reference 60).

Table F.3-7
MACCS2 Base Case Mean Results

Source Term	Release Category	Dose (p-rem)	Offsite Economic Cost ($)	Freq. (/yr)	Dose-Risk (p-rem/yr)	OECR ($/yr)
ST1	LG/EARLY	1.64E+07	1.68E+10	7.18E-08	1.18E+00	1.21E+03
ST2	SM/EARLY	1.80E+06	7.18E+09	1.66E-06	2.99E+00	1.19E+04
ST3	LATE	3.40E+04	8.81E+06	3.97E-06	1.35E-01	3.50E+01
ST4	BYPASS w/ AFW	1.26E+06	6.77E+09	1.23E-06	1.55E+00	8.33E+03
ST5	ISLOCA	1.02E+07	4.24E+10	2.88E-07	2.94E+00	1.22E+04
ST6	INTACT	4.96E+03	5.94E+05	1.22E-06	6.05E-03	7.25E-01
			FREQUENCY WEIGHTED TOTALS	**8.44E-06**	**8.79E+00**	**3.37E+04**

Table F.5-1a
DCPP Level 1 (Non-Fire / non-Seismic) IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
OR1	2.29E-02	1.19	OPERATOR COOLDOWN AND DEPRESSURIZE RCS	This event is associated with non-isolated SGTR, catastrophic seal LOCA or small break LOCA initiating events and this action is often in combination with failures to isolate the ruptured SG or to swap to recirculation mode. While the importance of this event may be overestimated due to conservative HRA techniques, some changes could be made to reduce the frequency of the sequences containing this action. Primary side isolation valves would simplify both the action to isolate a ruptured SG, the action to cooldown/depressurize the RCS after isolation, and help prevent induced SGTR events (SAMA 1). Automating the swap to recirculation mode would improve the reliability of the swap function (SAMA 2). ISGTR may be mitigated via a procedure modification that prevents clearing of RCS cold leg water seals, thereby obstructing a hot gas flowpath from the vessel to steam generator tubes (SAMA 24). Filling (or maintain filled) the steam generators just prior to core damage is a procedure change that provides mechanical scrubbing of fission products (SAMA 25).
RF3	2.78E-02	1.17	SWITCHOVER AFTER LLOCA OR MLOCA INITIATING EVENT	This event is associated with large and medium break LOCA initiating events and while the importance of the action may be overestimated due to conservative HRA modeling, automating the swap to recirculation mode would improve the reliability of the swap function (SAMA 2).
OX1	8.80E-03	1.14	OPERATOR DECIDES TO ISOLATE RUPTURED SG	Primary side isolation valves would simplify both the action to isolate a ruptured SG and the action to cooldown/depressurize the RCS after isolation (SAMA 1). ISGTR may be mitigated via a procedure modification that prevents clearing of RCS cold leg water seals, thereby obstructing a hot gas flowpath from the vessel to steam generator tubes (SAMA 24). Filling (or maintain filled) the steam generators just prior to core damage is a procedure change that provides mechanical scrubbing of fission products (SAMA 25).

Table F.5-1a
DCPP Level 1 (Non-Fire / non-Seismic) IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
REBAT	1.00E-01	1.12	Recovery from loss of all DC buses with OSP and vital AC buses available.	This event represents a screening value, and may be an overestimation. Consider performing a detailed post-initiator calculation for this event to determine if probability can be justifiably lowered. Linked to DC train failures. Providing an alternate DC generator that can be connected to a DC bus or directly to critical loads could mitigate DC system failures (SAMA 3).
GF1	4.07E-02	1.11	DG 1-3 (BUS F) STARTS & RUNS FOR 6 HR	Cross-tie from the opposite unit is available, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
DF1	4.71E-05	1.10	VITAL DC TRAIN F - A8F=S, A8H=S	The probability of this event reflects the failure of a DC bus given the availability of other 125Vdc and/or 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
DG3	1.28E-01	1.10	VITAL DC TRAIN G - A8F/A8G/A8H=S/S/S, DF=F	The probability of this event reflects the failure of a DC bus given the availability of other 125Vdc and/or 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).

Table F.5-1a
DCPP Level 1 (Non-Fire / non-Seismic) IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
GG2	3.11E-02	1.10	DG 1-2 (BUS G) : GF-F	Cross-tie from the opposite unit is available, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
DB1FGH	2.54E-06	1.10	DC 1F&1G&1H UNAVAIL-A8F=S, A8G=S, A8H=S, NONSEISMIC	The probability of this event reflects the failure of multiple DC buses given the availability of 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
GX	2.33E-04	1.09	3/3 DIESELS UNAVAILABLE	Cross-tie from the opposite unit is available, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
GH3	1.84E-01	1.09	DG 1-1 (BUS H) : GF-F,GG-F	Cross-tie from the opposite unit is available, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).

Table F.5-1a
DCPP Level 1 (Non-Fire / non-Seismic) IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
DH9	4.20E-01	1.09	VITAL DC TRN H - A8F/A8G/A8H=S/S/S, DF/DG=F/F	The probability of this event reflects the failure of a DC bus given the availability of other 125Vdc and/or 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
AW4	3.66E-02	1.08	SUPPORT FOR BOTH MDP'S UNAVAILABLE	Failure of support to both MDPs commonly occurs with loss of DC train H, which implies that use of the B.5.b pump could provide an alternate means of SG makeup (SAMA 6). Alternatively, an alternate DC generator could be used to provide control power to a MDAFW pump if 4kV power is available or to support the TD AFW pump (SAMA 3). This capability may be further enhanced by aligning makeup from the MCR, but pre-staging the equipment so that secondary side makeup can be aligned in time to mitigate transient scenarios would likely capture most of the benefit of these contributors.
D2F1	7.86E-05	1.07	125V DC BUS F (BATTERY) - ALL SUPPORT AVAILABLE	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
AF1	8.57E-04	1.06	All support available (with recovery)	4kV bus F is important because its failure could lead to a loss of both motor driven AFW trains with concurrent failure of DC bus H (i.e., DH10). MDAFW 1-2 fails because of Bus F 4KV failure and MDAFW 1-3 fails because of DC bus H control power. Providing an alternate DC generator to support the Train H loads could mitigate these failures (SAMA 3). Alternatively, the B.5.b pump (or a similar pump) could be used for alternate SG makeup (SAMA 6).

Table F.5-1a
DCPP Level 1 (Non-Fire / non-Seismic) IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
AWL1	7.15E-04	1.06	ALL SUPPORTS AVAILABLE	AWL1 is an intermediate SF used to calculate AW1L, which is related to loss of AFW support. While AFW reliability is high, providing an alternate means of maintaining secondary side makeup when the support systems fail will reduce the probability that Feed and Bleed will be required. Providing an alternate DC generator to support TD AFW operation is a potential means of mitigating these failures (SAMA 3). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
AW1L	7.15E-04	1.06	SAME AS AW1 - RCP'S TRIPPED AND NATURAL CIRCULATION MODE	AW1L is mostly related to LOOPPR, which results in loss of RCPs. While AFW reliability is high, providing an alternate means of maintaining secondary side makeup when the support systems fail will reduce the probability that Feed and Bleed will be required. Providing an alternate DC generator to support TD AFW operation is a potential means of mitigating these failures (SAMA 3). Alternatively, the B.5.b pump could be used to provide secondary side makeup (SAMA 6), or for SBO cases, a smaller sized EDG could be used to power the TD AFW battery chargers and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
RE6A	2.79E-01	1.06	Loss of Switchgear Ventilation, Top Event	Given that procedures already exist to provide alternate switchgear room cooling, further improvement to HVAC reliability would require the installation of an additional, independent train of HVAC (SAMA 8).
RE6	2.79E-03	1.06	Loss of Switch gear ventilation, Initiator	Given that procedures already exist to provide alternate switchgear room cooling, further improvement to HVAC reliability would require the installation of an additional, independent train of HVAC (SAMA 8).

Table F.5-1a
DCPP Level 1 (Non-Fire / non-Seismic) IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
OG1	2.82E-03	1.06	ALL SUPPORT AVAILABLE	This event is represents the availability of offsite power to the plant (including parts of the DCPP switchyard). While it is theoretically possible to improve the reliability of the switchyard equipment, it would be difficult to quantify the changes in reliability based on component changes. A more effective means of mitigation is considered to be providing the plant with the capability to survive a long term SBO. In this case, an alternate 480v AC generator could be used to power the station battery chargers to support long term TD AFW operation and power a new, self cooled, 480V AC PDP for primary side makeup (SAMA 5).
AA1F	8.57E-04	1.05	VITAL AC TRAIN F FAILS	AA1F is an "Intermediate" SF used to calculate AF1 and other conditional SFs associated with failure of 4KV buses G or H. MDAFW 1-2 fails because of Bus F 4KV failure and MDAFW 1-3 fails because of DC bus H control power. Providing an alternate DC generator to support the Train H loads could mitigate these failures (SAMA 3). Alternatively, the B.5.b pump (or a similar pump) could be used for alternate SG makeup (SAMA 6).
D2G2	2.51E-02	1.05	125V DC BUS G (BATTERY) - GIVEN D2F=F	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
DA3FGH	1.33E-06	1.05	VITAL DC TRAINS F, G AND H (2 HOUR) UNAVAILABLE	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).

Table F.5-1a
DCPP Level 1 (Non-Fire / non-Seismic) IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
DB2H	4.82E-03	1.04	DC 1H UNAVAIL- A8F=F, A8G=S, A8H=S, NONSEISMIC	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
OB1	2.26E-02	1.04	Loss of Instrument Air - PORV 474 DISABLED	Installation of a backup air supply (N2 bottles) could be used to support feed and bleed operations. This would prevent loss of IA in LOOP situations (SAMA 9).
OGA1	2.70E-01	1.04	FAILURE TO PROVIDE BACKFEED CAPABILITY GIVEN OG FAILED	This SF is important during loss of total AC power sources (i.e., 230KV and EDGs). Providing the plant with the capability to survive long term SBO scenarios would reduce the contribution of these events. In this case, an alternate 480V AC generator could be used to power the station battery chargers to support long term TD AFW operation and power a new, self cooled, 480V AC PDP for primary side makeup (SAMA 5).
OGAX	7.60E-04	1.04	FAILURE TO PROVIDE BACKFEED CAPABILITY GIVEN OG SUCCESSFUL	This SF is important when power is not available to the emergency 4kV buses. Providing the plant with the capability to survive long term SBO scenarios would reduce the contribution of these events. In this case, an alternate 480Vac generator could be used to power the station battery chargers to support long term TD AFW operation and power a new, self cooled, 480Vac PDP for primary side makeup (SAMA 5).
D2H3	6.77E-01	1.04	D2F-F, D2G-F	The probability of this event reflects the failure of multiple DC buses given the availability of 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).

Table F.5-1a
DCPP Level 1 (Non-Fire / non-Seismic) IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
DH10	4.84E-03	1.03	VITAL DC TRN H - A8F/A8G/A8H=S/S/F, DF/DG=S/S	As noted for SF AF1, loss of DC train H is important due to its contribution to scenarios that fail AFW. Providing an alternate DC generator to support the Train H loads could mitigate these failures (SAMA 3). Alternatively, the B.5.b pump (or a similar pump) could be used for alternate SG makeup (SAMA 6).
SV1	3.83E-07	1.03	1/2 TRAINS; OSP, 480V 1F, 1H AVAILABLE	Given that procedures already exist to provide alternate switchgear room cooling, further improvement to HVAC reliability would require the installation of an additional, independent train of HVAC (SAMA 8).
DGC1	7.50E-01	1.03	DIESEL GENERATOR (U1-U2) COUPLING FACTOR	This is related to the CCF potential between the units. While cross-tie between the units is not explicitly modeled, this factor demonstrated that limited credit would be available in SBO scenarios. In lieu of a inter-unit cross-tie, an alternate 480v AC generator could be used to power the station battery chargers to support long term TD AFW operation and power a new, self cooled, 480V AC PDP for primary side makeup (SAMA 5).
AH1	8.57E-04	1.03	DF-S, DG-S, AF-S, AG-S (with recovery)	The sequence associated with AH1 in this case is a loss of 480V SWGR ventilation. Given that procedures already exist to provide alternate switchgear room cooling, further improvement to HVAC reliability would require the installation of an additional, independent train of HVAC (SAMA 8).
CW2	5.00E-01	1.03	LOSS OF SUPPORT FOR CW PUMP TRAIN 1-1	Loss of circ water system has a minimal impact on CDF. The important SFs are the loss of CCW with Loss of DC BUS H initiator. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
PR1I	4.14E-02	1.03	480V 1F,1G AND 1H UNAVAIL: 1/3 PORV'S OR 1/3 SRV'S - MOV 8000A,B,C DISABLED	The scenario of concern involves loss of all thee trains of 480V power to PORV block valves either due to loss of DC systems or loss of offsite power and EDGs. Providing an alternate DC generator that can supply critical buses or specific loads could mitigate these contributors (SAMA 3).

Table F.5-1a
DCPP Level 1 (Non-Fire / non-Seismic) IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
D2G1	7.66E-05	1.03	125V DC BUS G (BATTERY) - ALL SUPPORT AVAILABLE (D2F=S)	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
AG1	8.57E-04	1.03	DF-S, AF-S, with recovery	This event is linked to the loss of DC train H. Providing an alternate DC generator to supply critical busses or specific loads could mitigate this contributor (SAMA 3).
AA1H	8.57E-04	1.03	VITAL AC TRAIN H FAILS	This is an "intermediate" SF associated with AH1, which contributes to loss of 480V SWGR ventilation scenarios. Given that procedures already exist to provide alternate switchgear room cooling, further improvement to HVAC reliability would require the installation of an additional, independent train of HVAC (SAMA 8). A swing EDG may provide a means of mitigating some Train H failures (SAMA 4).
DF2	4.82E-03	1.02	VITAL DC TRAIN F - A8F=S, A8H=F	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3).
RF1	1.65E-03	1.02	SWITCHOVER AFTER SLOCA OR B/F WITH CS FAILED	This event is used on scenarios involving both RCP seal LOCAs as well as standard SLOCAs. Automating the swap to recirculation mode could improve the reliability of the action (SAMA 2). Installation of high temperature RCP seals could help reduce or minimize the risk of RCP seal LOCAs (SAMA 10).
AWAA	7.24E-02	1.02	NO SUPPORT FOR 10% STM DMPS/TDP/MDP 1-2	Without electrical support for the 10 percent Steam Dump Valves, they are assumed to be failed. Loss of electrical support could be mitigated by providing alternate DC generator to supply specific buses or loads (SAMA 3).

Table F.5-1a
DCPP Level 1 (Non-Fire / non-Seismic) IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
GXGH	1.27E-03	1.02	2/3 DIESELS UNAVAILABLE (G & H)	EDG failures are important primarily in LOOP/SBO scenarios. Providing the plant with the capability to survive long term SBO scenarios would reduce the contribution of these events. In this case, an alternate 480V AC generator could be used to power the station battery chargers to support long term TD AFW operation and power a new, self cooled, 480V AC PDP for primary side makeup (SAMA 5). Alternatively, a diverse, swing EDG could be used as an alternate source of 4kV power (SAMA 4).
PR1H	2.81E-02	1.02	480V 1G AND 1H UNAVAIL: 1/3 PORV'S OR 1/3 SRV'S - MOV 8000B,C DISABLED	The scenario of concern involves loss of two trains of 480V power to PORV block valves either due to loss of DC systems or loss of offsite power and EDGs. Providing an alternate DC generator that can supply critical buses or specific loads could mitigate these contributors (SAMA 3).
DA2GH	1.97E-06	1.02	VITAL DC TRAINS G AND H (2 HOUR) UNAVAILABLE	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
PRX1H	2.81E-02	1.02	480V 1G AND 1H UNAVAIL: 1/3 PORV'S OR 1/3 SRV'S - MOV 8000B,C DISABLED	The scenario of concern involves loss of two trains of 480V power to PORV block valves either due to loss of DC systems or loss of offsite power and EDGs. Providing an alternate DC generator that can supply critical buses or specific loads could mitigate these contributors (SAMA 3).
D2H2A	8.31E-03	1.02	D2F-S, D2G-F	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).

Table F.5-1a
DCPP Level 1 (Non-Fire / non-Seismic) IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
VI2	7.60E-03	1.02	VESSEL INTEGRITY LOSS OF SECONDARY HEAT SINK	Failure of VI implies that vessel integrity has not been maintained (e.g. PORV is open) and the flow rate/circulation characteristic in the RPV are such that the LOCA cannot remove sufficient heat to prevent core damage. Generally, these scenarios could be avoided if secondary side heat removal remained available. Use of the B.5.b pump (or a similar pump) would provide an alternate means of maintaining secondary side heat removal (SAMA 6) and prevent entry into conditions where vessel integrity may be challenged.
CC3G	2.95E-04	1.02	LOSS OF 4KV BUS G	Cross-tie from the opposite unit is available, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
DB4F	4.82E-03	1.02	DC 1F UNAVAIL- A8F=S, A8G=S, A8H=F, NONSEISMIC	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
PRX1I	4.14E-02	1.02	480V 1F, 1G AND 1H UNAVAIL: 1/3 PORV'S OR 1/3 SRV'S - MOV 8000A,B,C DISABLED	The scenario of concern involves loss of all thee trains of 480V power to PORV block valves either due to loss of DC systems or loss of offsite power and EDGs. Providing an alternate DC generator that can supply critical buses or specific loads could mitigate these contributors (SAMA 3).

Table F.5-1a
DCPP Level 1 (Non-Fire / non-Seismic) IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
AA1G	8.57E-04	1.02	VITAL AC TRAIN G FAILS	This is an "intermediate" SF associated with AG1, which contributes to LOOP/SBO scenarios. A swing EDG may provide a means of mitigating some Train G failures (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
GG1	4.11E-02	1.02	DG 1-2 (BUS G) : GF-S	This SF is related to loss of power on 4kV bus G, which contributes to LOOP/SBO scenarios. A swing EDG may provide a means of mitigating some Train G failures (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).

Table F.5-1b
DCPP Level 1 Fire IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
FEF6	8.27E-02	1.69	CABLE SPREADING ROOM 1 GEOM/SEVERITY FACTOR	This SF is used to model the probability that the initiating fire in the cable spreading room will impact critical equipment based on the features of the fire area, including spatial dependence and the combustible loads in the room. The consequence of the scenario is that control of ASW and CCW is lost such that abandonment to the HSP is required to recover the systems. In addition, trip of the RCPs would be required to prevent an RCP seal LOCA. Given that the analysis does not credit the automatic detection and suppression equipment (total flood CO2) in the Cable Spreading Room, the risk of the scenario may be overestimated. However, improving the fire barriers for the ASW and CCW equipment in the Cable Spreading Room could further reduce the risk of these scenarios (SAMA 12).
FRE3	1.03E-02	1.69	CSR1 (J) OP ACT TRIP RCPs, RESTORE ASW/CCW	This SF is directly tied to SF FEF6 and represents the probability that the operators will fail to take the actions required to control the plant after a Cable Spreading Room fire that disables MCR controls for ASW and CCW. The primary concern is preventing an RCP seal LOCA, which requires trip of the RCP and any start and alignment actions required to restore CCW and ASW flow. Given that the analysis does not credit the automatic detection and suppression equipment (total flood CO2) in the Cable Spreading Room, the risk of the scenario may be overestimated. However, improving the fire barriers for the ASW and CCW equipment in the Cable Spreading Room could further reduce the risk of these scenarios (SAMA 12).

Table F.5-1b
DCPP Level 1 Fire IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
FHS1	2.88E-01	1.42	CSR2 CONDITIONAL PROBABILITY OF HOT SHORT (INST+SUST)	This SF is important mainly due to its contribution to CSR2 sequences and represents the probability of a fire-induced hot short given a fire at an affected circuit (applied to PORVs). CSR2 fires postulate fire damage to cables that affect the PORVs and the auxiliary relays of the pressurizer pressure and temperature controls, which are modeled as PORV LOCAs. The sequences including SF FHS1 also include FPR1, which indicates that the PORV does not reseat after attempted closure and the PORV LOCA conditions remains. No credit is taken for mitigating the PORV LOCA from outside the MCR. One potential means of reducing the risk of these scenarios would be to improve the PORV cable wrapping in the CSR (SAMA 13). Alternatively, fully automating feed and bleed initiation would remove the operator dependency for LOCA mitigation (SAMA 14).
FPR1	1.42E-02	1.42	CABLE SPREADING ROOM 2 - PROBABILITY OF PORV FAILING TO RESEAT	This SF represents the probability of a PORV failing to reseat given that it has failed open following a hot short in CSR2 sequences. CSR2 fires postulate fire damage to cables that affect the PORVs and the auxiliary relays of the pressurizer pressure and temperature controls, which are modeled as PORV LOCAs. Failure of FPR1 indicates that the PORV does not reseat after attempted closure of the PORV from the Hot Shutdown Panel and the PORV LOCA condition remains. No credit is taken for mitigating the PORV LOCA from outside the MCR. One potential means of reducing the risk of these scenarios would be to improve the PORV cable wrapping in the CSR (SAMA 13). Alternatively, fully automating feed and bleed initiation would remove the operator dependency for LOCA mitigation (SAMA 14).

Table F.5-1b
DCPP Level 1 Fire IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
FEF7	1.38E-01	1.38	CSR 2 - GEOM/SEVERITY FACTOR	This SF is used to model the probability that the initiating fire in the cable spreading room will impact critical equipment based on the features of the fire area, including spatial dependence and the combustible loads in the room. It is tied to the CSR2 fire events, which result in PORV LOCA scenarios and use of the Hot Shutdown Panel for alternate PORV control. No credit is taken for mitigating the PORV LOCA from outside the MCR. One potential means of reducing the risk of these scenarios would be to improve the PORV cable wrapping in the CSR (SAMA 13) to prevent the hot short from occurring. Alternatively, fully automating feed and bleed initiation would remove the operator dependency for LOCA mitigation (SAMA 14).
CC4GH	1.52E-02	1.07	LOSS OF 4KV BUSES G AND H	This SF is used with fire initiator FS7 and represents the probability that CCW fails given the loss of 4KV buses G and H. While power to one division is still available, failure of CCW on the remaining division results in the loss of RCP seal cooling (charging pump 11 lube oil cooling, thermal barrier cooling), and RHR heat removal capability (seal LOCA with no heat removal). These contributors could be addressed by providing the charging pumps (charging pump 11 for this specific case) with alternate lube oil cooling connections to fire water (SAMA 15). If alternate lube oil cooling can be aligned in a timely manner, the seal LOCA could be prevented and AFW could continue to remove heat using the steam generators. Alternatively, CCP 12 could be provided with a connection to an alternate power division (SAMA 17).
AW4	3.66E-02	1.04	SUPPORT FOR BOTH MDP'S UNAVAILABLE	The SF, which represents failure of the TD AFW pump, is primarily important due to fires which fail the two motor driven AFW pumps. These failures, combined with operator failure to initiate feed and bleed, result in core damage. These scenarios can be mitigated by providing an alternate, engine driven, high pressure AFW pump that could be aligned in a timely manner (SAMA 6).

Table F.5-1b
DCPP Level 1 Fire IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
AWBB	8.44E-03	1.04	SUPPORT FOR THE TDP AND MDP 1-2 UNAVAILABLE	This SF represents the failure of MD AFW pump 13 given the unavailability of the other two pumps (failed by loss of 4KV power caused by fire initiator FS7). These scenarios can be mitigated by providing an alternate, engine driven, high pressure AFW pump that could be aligned in a timely manner (SAMA 6).
FEF2	1.54E-02	1.03	CR VB4 GEOM/SEVERITY FACTOR	This SF is used to model the probability that the initiating fire in the MCR room will impact the controls for all 3 electrical divisions based on the features of the fire area, including spatial dependence and the combustible loads in the room. The largest contributor is an SBO resulting from failure to recover power and establish control at the Hot Shutdown Panel. Alternate SBO mitigation enhancements could be suggested, but the actual benefit would be limited due to operator dependence issues. Specifically, if the operators can't establish control at the relatively robust hot shutdown panel, then credit for controlling the plant with local injection sources would be difficult to justify. Installing automatic suppression within Vertical Board 4 is a potential means of preventing propagation between electrical divisions, which would greatly reduce the contributions from these fires (SAMA 16).
OB1	2.26E-02	1.03	Loss of Instrument Air - PORV 474 DISABLED	This SF is dominated by failure to establish feed and bleed after secondary side heat removal failure. These scenarios can be mitigated by providing an alternate, engine driven, high pressure AFW pump that could be aligned in a timely manner (SAMA 6).

Table F.5-1b
DCPP Level 1 Fire IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
SE9F	2.20E-01	1.03	NO SUPPORT FOR RCP SEAL COOLING WIHT FIRE WATER FAILED	This SF is important for fire initiators that fail buses G and F combined with subsequent failures that lead to loss of CCW while on power division is still available. Success of the action to provide alternate lube oil cooling to a CCP would allow continued RCP seal cooling when CCW is not available. Currently, the action to align alt CCP lube oil cooling requires operators to connect the fire water header to the CCP using fire hoses, which takes time and is complicated by the need to run hoses between the systems. The reliability of the action could be improved by installing a hard pipe connection between fire water and the CCPs so that alt lube oil cooling could be provided by simple valve manipulations (SAMA 15).

Table F.5-1c
DCPP Level 1 Seismic IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
AW1S	8.06E-04	1.167	SAME AS AW1 - SEISMIC 1 AND 2 (RWR UNAVAILABLE)	The primary contributor containing this SF is a low magnitude seismic event (SEIS1) in which AFW fails due to operator error to switch to an alternate water source given the CST and RWR are unavailable. Subsequent to the AFW failure, the operators fail to initiate feed and bleed. Automating feed and bleed initiation is a potential means of mitigating this scenario (SAMA 14).
AWS1	8.06E-04	1.167	ALL SUPPORTS AVAILABLE	This is an intermediate SF for AWS1. The primary contributor containing this SF is a low magnitude seismic event (SEIS1) in which AFW fails due to operator error to switch to an alternate water source the CST and RWR are unavailable. Subsequent to the AFW failure, the operators fail to initiate feed and bleed. Automating feed and bleed initiation is a potential means of mitigating this scenario (SAMA 14).
OB1SE	3.42E-01	1.170	Loss of Instrument Air - PORV 474 DISABLED	This is an intermediate SF for OB1S and is dominated by an operator error to initiate feed and bleed. The primary contributors containing this SF are low magnitude seismic events (SEIS1, SEIS2) in which AFW fails due to operator error to switch to an alternate water source after failure of the CST given the RWR is unavailable. Subsequent to the AFW failure, the operators fail to initiate feed and bleed. Automating feed and bleed initiation is a potential means of mitigating this scenario (SAMA 14).
OB1S	3.42E-01	1.155	Loss of Instrument Air, PORV 474 DISABLED - SEIS W/ESAM=30	This SF is dominated by operator error to initiate feed and bleed. The primary contributors containing this SF are low magnitude seismic events (SEIS1, SEIS2) in which AFW fails due to an operator error to switch to an alternate water source after failure of the CST given the RWR is unavailable. Subsequent to the AFW failure, the operators fail to initiate feed and bleed. Automating feed and bleed initiation is a potential means of mitigating this scenario (SAMA 14).

Table F.5-1c
DCPP Level 1 Seismic IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
SACSS4	3.92E-02	1.141	SEIS4, g Levels: 2.00E+00 to 2.500E+00	This SF represents the failure of all vital 4KV AC power given that the turbine building does not fail due to the seismic event. In most cases, the 230KV offsite supply is also failed and power is not available to the site at all. The loss of the 4KV AC systems implies that a recovery method may not rely on 4KV AC power or distribution mechanisms. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).
SACSS5	1.49E-01	1.099	SEIS5, g Levels: 2.500E+00 to 3.00E+00	This SF represents the failure of all vital 4KV AC power given that the turbine building does not fail due to the seismic event. In most cases, the 230KV offsite supply is also failed and power is not available to the site at all. The loss of the 4KV AC systems implies that a recovery method may not rely on 4KV AC power or distribution mechanisms. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).
SOP4	9.27E-01	1.061	SEIS4, g Levels: 2.00E+00 to 2.500E+00	This SF represents the loss of all offsite power and is based on the 230 KV switchyard seismic fragility, which is significantly stronger than the 500 KV switchyard seismic fragility. SOP4 almost always occurs with other on-site 4KV AC failure events that lead to SBOs, which sometimes includes distribution system failures. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).

Table F.5-1c
DCPP Level 1 Seismic IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
SDG4	1.69E-02	1.051	SEIS4, g Levels: 2.00E+00 to 2.500E+00	This SF represents the seismic failure of all six diesel generators and it is combined in the sequences with a seismically induced loss of offsite power, resulting in an SBO. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).
SOP5	9.84E-01	1.047	SEIS5, g Levels: 2.500E+00 to 3.00E+00	This SF represents the loss of all offsite power and is based on the 230 Kv switchyard seismic fragility, which is significantly stronger than the 500 Kv switchyard seismic fragility. SOP5 almost always occurs with other on-site 4KV AC failure events that lead to SBOs, which sometimes includes distribution system failures. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).
OC1SC	2.25E-01	1.038	OPERATOR RECOVERS RELAY CHATTER, ESAM=30	This SF represents the failure of the operators to reset seismic relay chatter given a seismically induced loss of offsite power. Without relay reset, on-site AC sources cannot be aligned to required loads. This could be addressed by replacing critical relays with high capacity relays (SAMA 19). Use of alternate generators and to power AFW and alternate seal injection pumps would not likely provide a large benefit given that the operator dependence issues would limit the credit for an additional action to mitigate loss of power; however, SAMA 18 could potentially reduce the risk of these events.
RT1S	8.51E-05	1.042	1/2 TRAINS (BOTH SSPS SIGNALS GENERATED) - SEIS W/ESAM=30	This SF represents the failure to depower the control rods after a plant trip signal. The dominant contributor is a failure of the breakers to change state combined with the operator failure to de-energize the RPS bus. A potential means of reducing the contribution of this SF is to use an alternate signal, such as AMSAC, to automate the de-energization of the 480V busses feeding the rod drive motor generator sets (SAMA 20).

Table F.5-1c
DCPP Level 1 Seismic IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RT1SE	8.51E-05	1.042	1/2 TRAINS (BOTH SSPS SIGNALS GENERATED) - SEIS W/ESAM=30	This in an intermediate SF for RT1S, which represents the failure to depower the control rods after a plant trip signal. The dominant contributor is a failure of the breakers to change state combined with the operator failure to de-energize the RPS bus. A potential means of reducing the contribution of this SF is to use an alternate signal, such as AMSAC, to automate the de-energization of the 480V busses feeding the rod drive motor generator sets (SAMA 20).
RT4S	3.12E-03	1.043	1/1 TRAIN (ONLY ONE SSPS SIGNAL GENERATED) - SEIS W/ESAM=30	This SF represents the failure to depower the control rods after a plant trip signal. The dominant contributor is operator failure to de-energize the RPS bus. A potential means of reducing the contribution of this SF is to use an alternate signal, such as AMSAC, to automate the de-energization of the 480V busses feeding the rod drive motor generator sets (SAMA 20).
RT4SE	3.12E-03	1.042	1/1 TRAIN (ONLY ONE SSPS SIGNAL GENERATED) - SEIS W/ESAM=30	This in an intermediate SF for RT4S, which represents the failure to depower the control rods after a plant trip signal. The dominant contributor is operator failure to de-energize the RPS bus. A potential means of reducing the contribution of this SF is to use an alternate signal, such as AMSAC, to automate the de-energization of the 480V busses feeding the rod drive motor generator sets (SAMA 20).
SACSS3	8.36E-03	1.035	SEIS3, g Levels: 1.75E+00 to 2.00E+00	This SF represents the failure of all vital 4KV AC power given that the turbine building does not fail due to the seismic event. In most cases, the 230KV offsite supply is also failed and power is not available to the site at all. The loss of the 4KV AC systems implies that a recovery methods may not rely on 4KV AC power or distribution mechanisms. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).

Table F.5-1c
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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
SCT5	2.72E-01	1.039	SEIS5, g Levels: 2.500E+00 to 3.00E+00	This SF represents the failure of the emergency AC power system due to seismically induced relay chatter. Without relay reset, on-site AC sources cannot be aligned to required loads. This could be addressed by replacing critical relays with high capacity relays (SAMA 19). Use of alternate generators and to power AFW and alternate seal injection pumps would not likely provide a large benefit given that the operator dependence issues would limit the credit for an additional action to mitigate loss of power; however, SAMA 18 could potentially reduce the risk of these events.
SDG5	6.67E-02	1.038	SEIS5, g Levels: 2.500E+00 to 3.00E+00	This SF represents the seismic failure of all six diesel generators and it is combined in the sequences with a seismically induced loss of offsite power, resulting in an SBO. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).
SOP6	9.97E-01	1.039	SEIS6, g Levels: 3.00E+00 to 3.99E+00	This SF represents the loss of all offsite power and is based on the 230 Kv switchyard seismic fragility, which is significantly stronger than the 500 Kv switchyard seismic fragility. SOP6 almost always occurs with other on-site 4KV AC failure events that lead to SBOs, which sometimes includes distribution system failures. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).
GF1S	6.55E-02	1.030	DG 1-3 (BUS F) STARTS & RUNS FOR 6 HR SEIS W/ESAM=30	This SF is important due to its inclusion in LOOP scenarios with other AC power related failures that lead to SBO evolutions. The largest of these contributors are combinations of other EDG failures. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).

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DCPP Level 1 Seismic IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
OC1SB	3.75E-02	1.025	OPERATOR RECOVERS RELAY CHATTER, ESAM=5	This SF represents the failure of the operators to reset seismic relay chatter given a seismically induced loss of offsite power. Without relay reset, on-site AC sources cannot be aligned to required loads. This could be addressed by replacing critical relays with high capacity relays (SAMA 19). Use of alternate generators and to power AFW and alternate seal injection pumps would not likely provide a large benefit given that the operator dependence issues would limit the credit for an additional action to mitigate loss of power; however, SAMA 18 could potentially reduce the risk of these events.
S11A	1.42E-02	1.028	SSPS TRAIN A FAILS (GENERAL TRANSIENT)	This intermediate SF for SA1, which is a failure of the "A" train of the solid state protection system, is important because SA1 is often paired with breaker failures that result in ATWS events, which are assumed to result in core damage for Seismic initiators. A potential means of reducing the contribution of this SF is to use an alternate signal, such as AMSAC, to automate the de-energization of the 480V busses feeding the rod drive motor generator sets (SAMA 20).
S11B	1.42E-02	1.028	SSPS TRAIN B FAILS (GENERAL TRANSIENT)	This intermediate SF for SB1, which is a failure of the "B" train of the solid state protection system, is important because SB1 is often paired with breaker failures that result in ATWS events, which are assumed to result in core damage for Seismic initiators. A potential means of reducing the contribution of this SF is to use an alternate signal, such as AMSAC, to automate the de-energization of the 480V busses feeding the rod drive motor generator sets (SAMA 20).
SA1	1.42E-02	1.030	GENERAL TRANSIENT	This SF, which is a failure of the "A" train of the solid state protection system, is often paired with breaker failures that result in ATWS events, which are assumed to result in core damage for Seismic initiators. A potential means of reducing the contribution of this SF is to use an alternate signal, such as AMSAC, to automate the de-energization of the 480V busses feeding the rod drive motor generator sets (SAMA 20).

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DCPP Level 1 Seismic IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
SACSS6	3.30E-01	1.030	SEIS6, g Levels: 3.00E+00 to 3.99E+00	This SF represents the failure of all vital 4KV AC power given that the turbine building does not fail due to the seismic event. In most cases, the 230KV offsite supply is also failed and power is not available to the site at all. The loss of the 4KV AC systems implies that a recovery methods may not rely on 4KV AC power or distribution mechanisms. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).
SDC4	8.47E-03	1.027	SEIS4, g Levels: 2.00E+00 to 2.500E+00	This SF represents the seismic failure of 125V DC power. This SF is typically combined with LOOP events, which result in SBO scenarios given that DC power is required for on-site power alignment. An alternate DC generator could be used to either power critical DC buses or to directly power critical DC equipment (SAMA 3). The generator would have to be stored in a seismically qualified area.
GG2S	7.09E-02	1.018	DG 1-2 (BUS G) : GF-F - SEIS W/ESAM=30	This SF is a DG 1-2 failure and it is typically combined with seismically induced LOOP and the failure of the other two station EDGs, which results in an SBO. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).
GYGS	8.64E-02	1.015	1/3 DIESELS UNAVAILABLE (BUS G) - SEIS W/ESAM=30	This SF represents failure of the Unit 2 DG 2-1 EDG, which appears in conjunction with seismically induced LOOP and relay chatter events that result in a SBO. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).

Table F.5-1c
DCPP Level 1 Seismic IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
SB1	1.38E-02	1.020	SA-S (GENERAL TRANSIENT)	This SF, which is a failure of the "B" train of the solid state protection system, is often paired with breaker failures that result in ATWS events, which are assumed to result in core damage for Seismic initiators. A potential means of reducing the contribution of this SF is to use an alternate signal, such as AMSAC, to automate the de-energization of the 480V busses feeding the rod drive motor generator sets (SAMA 20).
SCT4	1.34E-01	1.017	SEIS4, g Levels: 2.00E+00 to 2.500E+00	This SF represents the failure of the emergency AC power system due to seismically induced relay chatter. Without relay reset, on-site AC sources cannot be aligned to required loads. This could be addressed by replacing critical relays with high capacity relays (SAMA 19). Use of alternate generators and to power AFW and alternate seal injection pumps would not likely provide a large benefit given that the operator dependence issues would limit the credit for an additional action to mitigate loss of power; however, SAMA 18 could potentially reduce the risk of these events.
SDC5	3.82E-02	1.021	SEIS5, g Levels: 2.500E+00 to 3.00E+00	This SF represents the seismic failure of 125V DC power. This SF is typically combined with LOOP events, which result in SBO scenarios given that DC power is required for on-site power alignment. An alternate DC generator could be used to either power critical DC buses or to directly power critical DC equipment (SAMA 3). The generator would have to be stored in a seismically qualified area.
SOP3	8.27E-01	1.022	SEIS3, g Levels: 1.75E+00 to 2.00E+00	This SF represents the loss of all offsite power and is based on the 230 Kv switchyard seismic fragility, which is significantly stronger than the 500 Kv switchyard seismic fragility. SOP3 almost always occurs with other on-site 4KV AC failure events that lead to SBOs, which sometimes includes distribution system failures. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).

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DCPP Level 1 Seismic IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
AW1X	3.49E-03	1.008	SAME AS AW1 - SEISMIC 3 AND 4 (RWR UNAVAILABLE)	The primary contributors containing this SF are seismic events in which AFW fails due to operator error to switch to an alternate water source after failure of the CST given RWR is unavailable. Subsequent to the AFW failure, the operators fail to initiate feed and bleed. Automating feed and bleed initiation is a potential means of mitigating this scenario (SAMA 14).
AWS4	3.77E-02	1.010	SUPPORT FOR BOTH MDP'S UNAVAILABLE	This is an intermediate SF for AW4S. The primary contributors containing this SF are LOOP and SBO seismic events in which MD AFW is failed due to power dependencies. Subsequent to the TD AFW failure, feed and bleed is unavailable due to loss of power to one PORV and loss of instrument air for the other. Installation of a backup air supply (N2 bottles) could be used to support feed and bleed operations (SAMA 9).
AWX1	3.49E-03	1.008	ALL SUPPORTS AVAILABLE	This is an intermediate SF for AW1X. The primary contributors containing AW1X are seismic events in which AFW fails due to operator error to switch to an alternate water source after failure of the CST given RWR is unavailable. Subsequent to the AFW failure, the operators fail to initiate feed and bleed. Automating feed and bleed initiation is a potential means of mitigating this scenario (SAMA 14).
GH3S	2.08E-01	1.010	DG 1-1 (BUS H) : GF-F,GG-F - SEIS W/ESAM=30	This SF is a DG 1-1 failure and it is typically combined with seismically induced LOOP and the failure of the other two station EDGs, which results in an SBO. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).

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DCPP Level 1 Seismic IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
GXFHS	4.64E-03	1.008	2/3 DIESELS UNAVAILABLE (G & H) - SEIS W/ESAM=30	This is an intermediate SF for GH2FS. Most sequences that include GH2FS are those in which there is a LOOP/SBO in which MD AFW is failed due to power dependencies. Subsequent to the TD AFW failure, feed and bleed is unavailable due to loss of power to one PORV and loss of instrument air for the other. Installation of a backup air supply (N2 bottles) could be used to support feed and bleed operations (SAMA 9).
GXFS	6.55E-02	1.013	1/3 DIESELS UNAVAILABLE (BUS F) - SEIS W/ESAM=30	This is an intermediate SF for GF1S ("F" EDG failure). GF1S is important primarily due to its inclusion in LOOP scenarios with other AC power related failures that lead to SBO evolutions. The largest of these contributors are combinations of other EDG failures. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).
GXGS	6.55E-02	1.012	1/3 DIESELS UNAVAILABLE (BUS G) - SEIS W/ESAM=30	This is an intermediate SF for GG1S ("G" EDG failure). GG1S is important primarily in SBO sequences that include AC failures due to relay chatter (and no operator reset). Without relay reset, on-site AC sources cannot be aligned to required loads. This could be addressed by replacing critical relays with high capacity relays (SAMA 19). Use of alternate generators and to power AFW and alternate seal injection pumps would not likely provide a large benefit given that the operator dependence issues would limit the credit for an additional action to mitigate loss of power; however, SAMA 18 could potentially reduce the risk of these events.

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DCPP Level 1 Seismic IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
GXHS	6.55E-02	1.013	1/3 DIESELS UNAVAILABLE (BUS H) - SEIS W/ESAM=30	This is an intermediate SF for GH1S ("H" EDG failure). GH1S is important primarily in SBO sequences that include AC failures due to relay chatter (and no operator reset). Without relay reset, on-site AC sources cannot be aligned to required loads. This could be addressed by replacing critical relays with high capacity relays (SAMA 19). Use of alternate generators and to power AFW and alternate seal injection pumps would not likely provide a large benefit given that the operator dependence issues would limit the credit for an additional action to mitigate loss of power; however, SAMA 18 could potentially reduce the risk of these events.
GXS	9.67E-04	1.012	3/3 DIESELS UNAVAILABLE - SEIS W/ESAM=30	This is an intermediate SF for GH3S. This SF is used after a LOOP scenarios where the other 2 EDGs on the unit have also failed (and often with the opposite unit's EDGs) so that an SBO occurs. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).
GYFS	8.64E-02	1.015	1/3 DIESELS UNAVAILABLE (BUS F) - SEIS W/ESAM=30	This is an intermediate SF for TF1S, which represents failure of EDG 2-3. These are non-minimal for the Unit 1 model and are not actual contributors. No SAMA required.
GYHS	8.64E-02	1.015	1/3 DIESELS UNAVAILABLE (BUS H) - SEIS W/ESAM=30	This is an intermediate SF for TH1S, which represents failure of EDG 2-2. These are non-minimal for the Unit 1 model and are not actual contributors. No SAMA required.
RF1S	4.51E-02	1.014	SWITCHOVER AFTER SLOCA OR B/F WITH CS FAILED - SEISMIC W/ESAM=30	This SF is dominated by the operator error to perform swap to recirculation mode. The sequences including the SF typically include AFW hardware failures or stuck open PORV events that force bleed and feed operation. Automating feed and bleed initiation is a potential means of mitigating this scenario (SAMA 14). Alternatively, a high pressure, engine driven, secondary side makeup pump could be used to augment AFW capability assuming the pump is stored in a seismically qualified area (SAMA 6).

Table F.5-1c
DCPP Level 1 Seismic IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RF1SE	4.51E-02	1.014	SWITCHOVER AFTER SLOCA OR B/F WITH CS FAILED	This is an intermediate SF for RF1S, which is dominated by the operator error to perform swap to recirculation mode. These sequences typically include AFW hardware failures or stuck open PORV events that force bleed and feed operation. Automating feed and bleed initiation is a potential means of mitigating this scenario (SAMA 14). Alternatively, a high pressure, engine driven, secondary side makeup pump could be used to augment AFW capability assuming the pump is stored in a seismically qualified area (SAMA 6).
S12	5.29E-04	1.010	SSPS TRAIN A&B FAIL (GENERAL TRANSIENT)	This is an intermediate SF for SB2, which represents failure of the "B" SSPS channel given failure of the "A" channel. There are limited options available to address the sequences where operators fail to manually actuate the safety systems after automatic actuation has failed. A potential solution would be to install a redundant means of actuating AFW (SAMA 22).
SB2	3.74E-02	1.009	SA-F (GENERAL TRANSIENT)	This SF represents failure of the "B" SSPS channel given failure of the "A" channel. There are limited options available to address the sequences where operators fail to manually actuate the safety systems after automatic actuation has failed. A potential solution would be to install a redundant means of actuating AFW (SAMA 22).
SCT3	6.83E-02	1.010	SEIS3, g Levels: 1.75E+00 to 2.00E+00	This SF represents the failure of the emergency AC power system due to seismically induced relay chatter. Without relay reset, on-site AC sources cannot be aligned to required loads. This could be addressed by replacing critical relays with high capacity relays (SAMA 19). Use of alternate generators and to power AFW and alternate seal injection pumps would not likely provide a large benefit given that the operator dependence issues would limit the credit for an additional action to mitigate loss of power; however, SAMA 18 could potentially reduce the risk of these events.

Table F.5-1c
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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
SCT6	4.51E-01	1.012	SEIS6, g Levels: 3.00E+00 to 3.99E+00	This SF represents the failure of the emergency AC power system due to seismically induced relay chatter. Without relay reset, on-site AC sources cannot be aligned to required loads. This could be addressed by replacing critical relays with high capacity relays (SAMA 19). Use of alternate generators and to power AFW and alternate seal injection pumps would not likely provide a large benefit given that the operator dependence issues would limit the credit for an additional action to mitigate loss of power; however, SAMA 18 could potentially reduce the risk of these events.
SDC3	2.24E-03	1.009	SEIS3, g Levels: 1.75E+00 to 2.00E+00	This SF represents the seismic failure of 125V DC power. This SF is typically combined with LOOP events, which result in SBO scenarios given that DC power is required for on-site power alignment. An alternate DC generator could be used to either power critical DC buses or to directly power critical DC equipment (SAMA 3). The generator would have to be stored in a seismically qualified area.
SDC6	1.26E-01	1.009	SEIS6, g Levels: 3.00E+00 to 3.99E+00	This SF represents the seismic failure of 125V DC power. This SF is typically combined with LOOP events, which result in SBO scenarios given that DC power is required for on-site power alignment. An alternate DC generator could be used to either power critical DC buses or to directly power critical DC equipment (SAMA 3). The generator would have to be stored in a seismically qualified area.
SDG3	4.15E-03	1.014	SEIS3, g Levels: 1.75E+00 to 2.00E+00	This SF represents the seismic failure of all six diesel generators and it is combined in the sequences with a seismically induced loss of offsite power, resulting in an SBO. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).

Table F.5-1c
DCPP Level 1 Seismic IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
SDG6	1.83E-01	1.014	SEIS6, g Levels: 3.00E+00 to 3.99E+00	This SF represents the seismic failure of all six diesel generators and it is combined in the sequences with a seismically induced loss of offsite power, resulting in an SBO. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18).
SOP2	5.27E-01	1.011	SEIS2, g Levels: 1.25E-00 to 1.75E+00	This SF represents the loss of all offsite power and is based on the 230 Kv switchyard seismic fragility, which is significantly stronger than the 500 Kv switchyard seismic fragility. SOP2 almost always occurs with other on-site 4KV AC failure events that lead to SBOs, which sometimes includes distribution system failures. A potential solution is to use an alternate 480V AC generator to supply the battery chargers for long term AFW support in conjunction with a self cooled, 480V AC RCP seal injection pump that can be rapidly aligned (SAMA 18). The cases that include AFW failures could be addressed by a high pressure, engine driven, secondary side makeup pump assuming the pump is stored in a seismically qualified area (SAMA 6).
SSG4	3.00E-03	1.009	SEIS4, g Levels: 2.00E+00 to 2.500E+00	This top event represents the seismic failure of the steam generator supports and postulated failure of the reactor coolant system and steam connecting piping. Failure of this top event is modeled as leading to core damage. The top event failure also is modeled as failing containment because it results in high containment internal pressure. A potential means of reducing the contribution of these sequences is to reinforce the SG support structures so that they are more likely to survive more powerful earthquakes (in this case, events with peak accelerations of 2 to 2.5g) (SAMA 23).

Table F.5-2a
DCPP Level 2 (ST1 / ST5)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
SM2	1.33E-02	1.818	2700 GPM LEAK RATE NORMALIZED TO 150	This event represents the failure probability of an RHR ISLOCA to normalize from a leak rate of 2700 gpm to 150 gpm. Numerous failure mechanisms could contribute to a sustained elevated leakage rate, such as valve seat leakage and valve stem packing blowby. While it is possible to improve the isolation pathways between the RCS and RHR, it may be unlikely to appreciably reduce the importance of this event. (No specific SAMA identified)
CECET1	2.80E-02	1.267	no description entered	This event represents containment failure due to early hydrogen burn. A potential SAMA would be to provide the capability of inerting the containment atmosphere during normal operation by displacing the O2 content with N2 by an amount that cannot sustain combustion (SAMA 11).
HECET2	7.10E-01	1.231	no description entered	This event represents containment failure due to hydrogen burn within 4 hours of vessel breach. This scenario is similar to event CECET1. See SAMA 11.
SM1	1.48E-02	1.159	2700 GPM LEAK RATE NORMALIZED TO 150	This event represents the failure probability of an RHR ISLOCA to normalize from a leak rate of 2700 gpm to 150 gpm. Numerous failure mechanisms could contribute to a sustained elevated leakage rate, such as valve seat leakage and valve stem packing blowby. While it is possible to improve the isolation pathways between the RCS and RHR, it may be unlikely to appreciably reduce the importance of this event. (No specific SAMA identified)
RF3	2.78E-02	1.109	SWITCHOVER AFTER LLOCA OR MLOCA INITIATING EVENT	This event is associated with large and medium break LOCA initiating events and while the importance of the action may be overestimated due to conservative HRA modeling, automating the swap to recirculation mode would improve the reliability of the swap function (SAMA 2).

Table F.5-2a
DCPP Level 2 (ST1 / ST5)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
DF1	4.71E-05	1.067	VITAL DC TRAIN F - A8F=S, A8H=S	The probability of this event reflects the failure of a DC bus given the availability of other 125Vdc and/or 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
DG3	1.28E-01	1.066	VITAL DC TRAIN G - A8F/A8G/A8H=S/S/S, DF=F	The probability of this event reflects the failure of a DC bus given the availability of other 125Vdc and/or 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
DB1FGH	2.54E-06	1.066	DC 1F&1G&1H UNAVAIL-A8F=S, A8G=S, A8H=S, NONSEISMIC	The probability of this event reflects the failure of multiple DC buses given the availability of 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
DH9	4.20E-01	1.065	VITAL DC TRN H - A8F/A8G/A8H=S/S/S, DF/DG=F/F	The probability of this event reflects the failure of a DC bus given the availability of other 125Vdc and/or 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
D2F1	7.86E-05	1.050	125V DC BUS F (BATTERY) - ALL SUPPORT AVAILABLE	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).

Table F.5-2a
DCPP Level 2 (ST1 / ST5)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
IPCET1	7.20E-01	1.049	no description entered	This event represents a containment phenomenology probability; no fault tree for this 'system' exists; the split fractions are basically equations that set the split fraction to a probability. The top event is defined as INDUCED RCS HOT LEG OR SURGE LINE FAILURE, which, depicts RCS high temperature / pressure causing a failure of the RCS pressure boundary. Investigation of related sequences reveals significant AC/DC power dependencies. Hence, SAMAs 3, 4 and 5 may provide benefit in reducing the importance of this event. (SAMA 3,4,5)
D2G2	2.51E-02	1.045	125V DC BUS G (BATTERY) - GIVEN D2F=F	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
DA3FGH	1.33E-06	1.045	VITAL DC TRAINS F, G AND H (2 HOUR) UNAVAILABLE	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
D2H3	6.77E-01	1.043	D2F-F, D2G-F	The probability of this event reflects the failure of multiple DC buses given the availability of 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
MUV	3.68E-02	1.038	ILOCA - FAILURE TO ESTABLISH MAKEUP TO RWST	This event represents the failure of the SFP system to makeup to the RWST following an ISLOCA at either the RHR pump suction or discharge. Automating the swap to recirculation mode would improve the probability of this event (SAMA 2).

Table F.5-2a
DCPP Level 2 (ST1 / ST5)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
C2CT3	1.80E-02	1.028	no description entered	This event represents a containment phenomenology probability; no fault tree for this 'system' exists; the split fractions are basically equations that set the split fraction to a probability. The top event is defined as C2CET (CONTAINMENT FAILURE AT VESSEL BREACH) which depicts containment failure upon various initiating events leading to vessel breach. This event shows up in higher level sequences where there exists a dependency on switchgear ventilation. Hence, SAMA 8 may provide some benefit to reduce the importance of this event. (SAMA 8)
L2CT3	3.30E-01	1.028	no description entered	This event represents a containment phenomenology probability; no fault tree for this 'system' exists; the split fractions are basically equations that set the split fraction to a probability. This event shows up in the same sequences as C2CT3. The top event is defined as L2CET (LARGE CONTAINMENT FAILURE AT VESSEL BREACH) which depicts containment failure upon various initiating events leading to vessel breach. This event shows up in higher level sequences where there exists a dependency on switchgear ventilation. Hence, SAMA 8 may provide some benefit to reduce the importance of this event. (SAMA 8)

Table F.5-2a
DCPP Level 2 (ST1 / ST5)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
OR1	2.29E-02	1.027	OPERATOR COOLDOWN AND DEPRESSURIZE RCS	This event is associated with non-isolated SGTR, catastrophic seal LOCA or small break LOCA initiating events and this action is often in combination with failures to isolate the ruptured SG or to swap to recirculation mode. While the importance of this event may be overestimated due to conservative HRA techniques, some changes could be made to reduce the frequency of the sequences containing this action. Primary side isolation valves would simplify both the action to isolate a ruptured SG, the action to cooldown/depressurize the RCS after isolation, and help prevent induced SGTR events (SAMA 1). Automating the swap to recirculation mode would improve the reliability of the swap function (SAMA 2). ISGTR may be mitigated via a procedure modification that prevents clearing of RCS cold leg water seals, thereby obstructing a hot gas flowpath from the vessel to steam generator tubes (SAMA 24). Filling (or maintain filled) the steam generators just prior to core damage is a procedure change that provides mechanical scrubbing of fission products (SAMA 25).
ADCET1	8.05E-01	1.026	no description entered	This event represents a containment phenomenology probability; no fault tree for this 'system' exists; the split fractions are basically equations that set the split fraction to a probability. The top event is defined as ADCET (Failure to Arrest Damage and Prevent Vessel Breach) which depicts containment failure upon various initiating events leading to vessel breach. This event shows up in higher level sequences where there exists a dependency on 4KV power and switchgear ventilation. Hence, SAMAs 4, 5 and 8 may provide some benefit to reduce the importance of this event. (SAMA 4,5,8)

Table F.5-2a
DCPP Level 2 (ST1 / ST5)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
VC1	7.42E-02	1.026	560 GPM LEAK RATE NORMALIZED TO 150 GPM	This event represents the failure probability of an RHR ISLOCA to normalize from a leak rate of 560 gpm to 150 gpm. Numerous failure mechanisms could contribute to a sustained elevated leakage rate, such as valve seat leakage and valve stem packing blowby. While it is possible to improve the isolation pathways between the RCS and RHR, it may be unlikely to appreciably reduce the importance of this event. (No specific SAMA identified)
AW1L	7.15E-04	1.024	SAME AS AW1 - RCP'S TRIPPED AND NATURAL CIRCULATION MODE	AW1L is mostly related to LOOPPR, which results in loss of RCPs. While AFW reliability is high, providing an alternate means of maintaining secondary side makeup when the support systems fail will reduce the probability that Feed and Bleed will be required. Providing an alternate DC generator to support TD AFW operation is a potential means of mitigating these failures (SAMA 3). Alternatively, the B.5.b pump could be used to provide secondary side makeup (SAMA 6), or for SBO cases, a smaller sized EDG could be used to power the TD AFW battery chargers and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
AWL1	7.15E-04	1.024	ALL SUPPORTS AVAILABLE	AWL1 is an intermediate SF used to calculate AW1L, which is related to loss of AFW support. While AFW reliability is high, providing an alternate means of maintaining secondary side makeup when the support systems fail will reduce the probability that Feed and Bleed will be required. Providing an alternate DC generator to support TD AFW operation is a potential means of mitigating these failures (SAMA 3). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
HECET1	7.10E-01	1.024	no description entered	This event represents containment failure due to hydrogen burn within 4 hours of vessel breach. This scenario is similar to event CECET1. See SAMA 11.

Table F.5-2a
DCPP Level 2 (ST1 / ST5)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
AW4	3.66E-02	1.024	SUPPORT FOR BOTH MDP'S UNAVAILABLE	Failure of support to both MDPs commonly occurs with loss of DC train H, which implies that use of the B.5.b pump could provide an alternate means of SG makeup (SAMA 6). Alternatively, an alternate DC generator could be used to provide control power to a MDAFW pump if 4kV power is available or to support the TD AFW pump (SAMA 3). This capability may be further enhanced by aligning makeup from the MCR, but pre-staging the equipment so that secondary side makeup can be aligned in time to mitigate transient scenarios would likely capture most of the benefit of these contributors.
REBAT	1.00E-01	1.021	Recovery from loss of all DC buses with OSP and vital AC buses available.	This event represents a screening value, and may be an overestimation. Consider performing a detailed post-initiator calculation for this event to determine if probability can be justifiably lowered. Linked to DC train failures. Providing an alternate DC generator that can be connected to a DC bus or directly to critical loads could mitigate DC system failures (SAMA 3).

[1] ST1 and ST5 refer to release categories Large Early and ISLOCA, respectively

Table F.5-2b
DCPP Level 2 (ST2 / ST4)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
OR1	2.29E-02	1.614	OPERATOR COOLDOWN AND DEPRESSURIZE RCS	This event is associated with non-isolated SGTR, catastrophic seal LOCA or small break LOCA initiating events and this action is often in combination with failures to isolate the ruptured SG or to swap to recirculation mode. While the importance of this event may be overestimated due to conservative HRA techniques, some changes could be made to reduce the frequency of the sequences containing this action. Primary side isolation valves would simplify both the action to isolate a ruptured SG, the action to cooldown/depressurize the RCS after isolation, and help prevent induced SGTR events (SAMA 1). Automating the swap to recirculation mode would improve the reliability of the swap function (SAMA 2). ISGTR may be mitigated via a procedure modification that prevents clearing of RCS cold leg water seals, thereby obstructing a hot gas flowpath from the vessel to steam generator tubes (SAMA 24). Filling (or maintain filled) the steam generators just prior to core damage is a procedure change that provides mechanical scrubbing of fission products (SAMA 25).
OX1	8.80E-03	1.529	OPERATOR DECIDES TO ISOLATE RUPTURED SG	Primary side isolation valves would simplify both the action to isolate a ruptured SG and the action to cooldown/depressurize the RCS after isolation (SAMA 1). ISGTR may be mitigated via a procedure modification that prevents clearing of RCS cold leg water seals, thereby obstructing a hot gas flowpath from the vessel to steam generator tubes (SAMA 24). Filling (or maintain filled) the steam generators just prior to core damage is a procedure change that provides mechanical scrubbing of fission products (SAMA 25).
REBAT	1.00E-01	1.298	Recovery from loss of all DC buses with OSP and vital AC buses available.	This event represents a screening value, and may be an overestimation. Consider performing a detailed post-initiator calculation for this event to determine if probability can be justifiably lowered. Linked to DC train failures. Providing an alternate DC generator that can be connected to a DC bus or directly to critical loads could mitigate DC system failures (SAMA 3).

Table F.5-2b
DCPP Level 2 (ST2 / ST4)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
DF1	4.71E-05	1.214	VITAL DC TRAIN F - A8F=S, A8H=S	The probability of this event reflects the failure of a DC bus given the availability of other 125Vdc and/or 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
DG3	1.28E-01	1.213	VITAL DC TRAIN G - A8F/A8G/A8H=S/S/S, DF=F	The probability of this event reflects the failure of a DC bus given the availability of other 125Vdc and/or 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
DB1FGH	2.54E-06	1.213	DC 1F&1G&1H UNAVAIL- A8F=S, A8G=S, A8H=S, NONSEISMIC	The probability of this event reflects the failure of multiple DC buses given the availability of 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
DH9	4.20E-01	1.213	VITAL DC TRN H - A8F/A8G/A8H=S/S/S, DF/DG=F/F	The probability of this event reflects the failure of a DC bus given the availability of other 125Vdc and/or 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
RE6	2.79E-03	1.134	Loss of Switch gear ventilation, Initiator	Given that procedures already exist to provide alternate switchgear room cooling, further improvement to HVAC reliability would require the installation of an additional, independent train of HVAC (SAMA 8).
D2F1	7.86E-05	1.105	125V DC BUS F (BATTERY) - ALL SUPPORT AVAILABLE	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).

Table F.5-2b
DCPP Level 2 (ST2 / ST4)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
D2G2	2.51E-02	1.102	125V DC BUS G (BATTERY) - GIVEN D2F=F	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
DA3FGH	1.33E-06	1.101	VITAL DC TRAINS F, G AND H (2 HOUR) UNAVAILABLE	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
D2H3	6.77E-01	1.101	D2F-F, D2G-F	The probability of this event reflects the failure of multiple DC buses given the availability of 480Vac buses. As such, a backup independent DC power supply system capable of being connected to the affected bus in a timely manner may lower the importance of this event (SAMA 3).
OG1	2.82E-03	1.055	ALL SUPPORT AVAILABLE	This event is represents the availability of offsite power to the plant (including parts of the DCPP switchyard). While it is theoretically possible to improve the reliability of the switchyard equipment, it would be difficult to quantify the changes in reliability based on component changes. A more effective means of mitigation is considered to be providing the plant with the capability to survive a long term SBO. In this case, an alternate 480v AC generator could be used to power the station battery chargers to support long term TD AFW operation and power a new, self cooled, 480V AC PDP for primary side makeup (SAMA 5).
AWAA	7.24E-02	1.048	NO SUPPORT FOR 10% STM DMPS/TDP/MDP 1-2	Without electrical support for the 10 percent Steam Dump Valves, they are assumed to be failed. Loss of electrical support could be mitigated by providing alternate DC generator to supply specific buses or loads (SAMA 3).

Table F.5-2b
DCPP Level 2 (ST2 / ST4)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
GG2	3.11E-02	1.047	DG 1-2 (BUS G) : GF-F	Cross-tie from the opposite unit is available, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
GF1	4.07E-02	1.047	DG 1-3 (BUS F) STARTS & RUNS FOR 6 HR	Cross-tie from the opposite unit is available, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
GH3	1.84E-01	1.046	DG 1-1 (BUS H) : GF-F,GG-F	Cross-tie from the opposite unit is available, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).

Table F.5-2b
DCPP Level 2 (ST2 / ST4)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
GX	2.33E-04	1.046	3/3 DIESELS UNAVAILABLE	Cross-tie from the opposite unit is available, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
D2G1	7.66E-05	1.042	125V DC BUS G (BATTERY) - ALL SUPPORT AVAILABLE (D2F=S)	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
PR1H	2.81E-02	1.041	480V 1G AND 1H UNAVAIL: 1/3 PORV'S OR 1/3 SRV'S - MOV 8000B,C DISABLED	The scenario of concern involves loss of two trains of 480V power to PORV block valves either due to loss of DC systems or loss of offsite power and EDGs. Providing an alternate DC generator that can supply critical buses or specific loads could mitigate these contributors (SAMA 3).
PRX1H	2.81E-02	1.041	480V 1G AND 1H UNAVAIL: 1/3 PORV'S OR 1/3 SRV'S - MOV 8000B,C DISABLED	The scenario of concern involves loss of two trains of 480V power to PORV block valves either due to loss of DC systems or loss of offsite power and EDGs. Providing an alternate DC generator that can supply critical buses or specific loads could mitigate these contributors (SAMA 3).
DA2GH	1.97E-06	1.039	VITAL DC TRAINS G AND H (2 HOUR) UNAVAILABLE	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).

Table F.5-2b
DCPP Level 2 (ST2 / ST4)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
D2H2A	8.31E-03	1.038	D2F-S, D2G-F	An alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
OGA1	2.70E-01	1.038	FAILURE TO PROVIDE BACKFEED CAPABILITY GIVEN OG FAILED	This SF is important during loss of total AC power sources (i.e., 230kV and EDGs). Providing the plant with the capability to survive long term SBO scenarios would reduce the contribution of these events. In this case, an alternate 480V AC generator could be used to power the station battery chargers to support long term TD AFW operation and power a new, self cooled, 480V AC PDP for primary side makeup (SAMA 5).
OGAX	7.60E-04	1.038	FAILURE TO PROVIDE BACKFEED CAPABILITY GIVEN OG SUCCESSFUL	This SF is important when power is not available to the emergency 4kV buses. Providing the plant with the capability to survive long term SBO scenarios would reduce the contribution of these events. In this case, an alternate 480V AC generator could be used to power the station battery chargers to support long term TD AFW operation and power a new, self cooled, 480V AC PDP for primary side makeup (SAMA 5).
GG1	4.11E-02	1.037	DG 1-2 (BUS G) : GF-S	This SF is related to loss of power on 4kV bus G, which contributes to LOOP/SBO scenarios. A swing EDG may provide a means of mitigating some Train G failures (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).
AG1	8.57E-04	1.033	DF-S, AF-S, with recovery	This event is linked to the loss of DC train H. Providing an alternate DC generator to supply critical busses or specific loads could mitigate this contributor (SAMA 3).

Table F.5-2b
DCPP Level 2 (ST2 / ST4)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
GXGH	1.27E-03	1.029	2/3 DIESELS UNAVAILABLE (G & H)	EDG failures are important primarily in LOOP/SBO scenarios. Providing the plant with the capability to survive long term SBO scenarios would reduce the contribution of these events. In this case, an alternate 480V AC generator could be used to power the station battery chargers to support long term TD AFW operation and power a new, self cooled, 480V AC PDP for primary side makeup (SAMA 5). Alternatively, a diverse, swing EDG could be used as an alternate source of 4kV power (SAMA 4).
MS2	1.00E+00	1.029	no description entered	This event models successful isolation of MSIVs and steam dumps. Given that MSIV/steam dump operability may be important to reduce release probability, and DC power is required to maintain MSIV/steam dump functionality (MS2 shows up in sequences where DC power is compromised), an alternate DC generator could be used to supply power to a specific set of buses or critical loads in the event of DC battery failure (SAMA 3). Alternatively, the battery chargers could be replaced or modified so that they can supply the DC train when the batteries are isolated from the circuit (SAMA 7).
GH2G	2.62E-02	1.029	DG 1-1 (BUS H) : GF-S, GG-F	Cross-tie from the opposite unit is available, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).

Table F.5-2b
DCPP Level 2 (ST2 / ST4)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
DGC1	7.50E-01	1.028	DIESEL GENERATOR (U1-U2) COUPLING FACTOR	This is related to the CCF potential between the units. While cross-tie between the units is not explicitly modeled, this factor demonstrated that limited credit would be available in SBO scenarios. In lieu of a inter-unit cross-tie, an alternate 480v AC generator could be used to power the station battery chargers to support long term TD AFW operation and power a new, self cooled, 480V AC PDP for primary side makeup (SAMA 5).
OP1	5.71E-04	1.027	OPERATOR FAILS TO TERMINATE SAFETY INJECTION	This event represents operator failure to terminate ECCS during SGTR initiating event. Given the relatively long time window available for action, combined with the frequent simulator and classroom training associated with this event, it is unlikely any further benefit can be obtained by revising the existing HEP analysis. (No specific SAMA identified)
IV1	5.77E-04	1.023	ISOLATE RUPTURED SG - ALL SUPPORT AVAILA	This event depicts failure to isolate a ruptured SG given all support systems are available. Captured within this event is HEP (ZHEOX1) which analyzes operator reliability to perform this function. Given the relatively short time window available for action, combined with the frequent simulator and classroom training associated with this event, it is unlikely any further benefit can be obtained by revising the existing HEP analysis. Hence, it is not expected that this event importance can be lowered. (No specific SAMA identified)

Table F.5-2b
DCPP Level 2 (ST2 / ST4)[1] IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
P2CET3	2.82E-01	1.023	no description entered	This event is associated with top event RCS PRESSURE AT VESSEL BREACH EXCEEDS 650 PSIA. Further investigation of sequences reveals a consistent dependability on DGs. Cross-tie from the opposite unit is available, but common cause failures would likely limit the credit associated with including the capability in the model. Installation of a self-contained, independent swing diesel, not dependent on external support systems, would provide increased defense in depth and should be considered for loss of onsite emergency AC power sources (SAMA 4). Alternatively, a smaller sized EDG could be used to power the AFW battery chargers for long term SBO operation and a new, self cooled, 480V AC PDP could be used for primary side makeup (SAMA 5).

[1] ST2 and ST4 refer to release categories Small Early and Bypass with AFW, respectively

Table F.5-3
DCPP Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate[1]	Retained	Phase 1 Baseline Disposition
1	Install Primary Side SG Isolation Valves	The availability of primary side steam generator isolation vales would provide a simple means of isolating ruptured SGs. While secondary side isolation capability exists, these valves would help avoid challenges to secondary side integrity due to failure to rapidly cooldown the primary side.	Internal Events PRA Importance Review	$83,748,120	No	Screened based on implementation cost greater than MACR.
2	Automate Swap to Recirculation	The operators are well trained on the action to transition the RCS injection systems to recirculation mode, but automating the process will further improve reliability and reduce the contribution of this action to core damage scenarios.	Internal Events PRA Importance Review	$6,509,256	Yes	See Section F.6.1
3	Alternate DC Generator	In order to mitigate DC system failures, an alternate DC generator could be used to directly power a bus (bypasses charger faults) or directly power critical loads (bypasses distribution failures). The generator should be stored in a seismically qualified area so that it would potentially be available to respond in seismic scenarios.	Internal Events PRA Importance Review, Seismic Importance Review	$5,863,176	Yes	See Section F.6.2
4	Install a Self-Contained Swing EDG	One of the most effective means of reducing SBO scenarios is to provide a diverse emergency power supply that can support all of the equipment normally supplied by an existing EDG.	Internal Events PRA Importance Review	$58,800,458	No	Screened based on implementation cost greater than MACR.

Table F.5-3
DCPP Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate[(1)]	Retained	Phase 1 Baseline Disposition
5	Use an Alternate EDG to Support Long Term AFW Operation and a 480V AC Self-Cooled PDP for Primary Side Makeup	A low costly SBO mitigation strategy is to use a small, alternate EDG to power a station battery charger for level instrumentation and AFW control. In addition, if power can be supplied to a 480V AC self-cooled positive displacement pump, primary makeup could be maintained to mitigate a seal LOCA. This SAMA is geared towards mitigating the higher probability (low leakrate) RCP seal LOCA (21 gpm per pump, 84 gpm total), which accounts for 78 percent of all seal LOCAs.	Internal Events PRA Importance Review	$6,441,418	Yes	See Section F.6.3
6	Use Alternate Engine-Driven HP Pump for Secondary Side Makeup	Ensuring that an alternate, engine-driven, HP pump could be rapidly aligned to provide secondary side makeup in transient scenarios could address many loss of AFW scenarios. This may require pre-staging equipment in seismically qualified areas and ensuring the pump and piping can be quickly aligned to the AFW injection line/suction source. If a higher pressure pump is required so that the system can be used to mitigate early loss of secondary side makeup cases, the cost should account for this.	Internal Events PRA Importance Review, Seismic Importance Review	$14,475,422	No	Screened based on implementation cost greater than MACR. See Section F.7.2.1.1 for 95th percentile impact on Phase 1 screening.
7	Replace or Modify the Battery Chargers to Operate Without the Batteries	Typically, battery chargers are not designed to support all DC demands without the batteries. If they can be replaced or modified so that they could do this, it would mitigate battery failure scenarios.	Internal Events PRA Importance Review	$2,552,563	Yes	See Section F.6.4
8	Install an Additional Train of Switchgear Room HVAC	Alternate Switchgear Room cooling procedures already exist for DCPP, but the loss of room cooling is still an important issue. While costly, a potential means of reducing the HVAC failure contribution would be to install an independent train of HVAC.	Internal Events PRA Importance Review	$6,376,810	Yes	See Section F.6.5

Table F.5-3
DCPP Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate(1)	Retained	Phase 1 Baseline Disposition
9	Backup Air System for PORV PCV 474	Currently, loss of offsite power results in the loss of the IA system. Changing the air supply to PCV 474 (Pressurizer PORV) to a class I backup air supply would prevent this and reduce the loss of IA contributions to core damage.	Internal Events PRA Importance Review, Seismic Importance Review	$1,692,730	Yes	See Section F.6.6
10	Install High Temperature RCP Seals	Mitigation strategies to supply alternate RCP seal cooling can reduce the risk of RCP seal LOCAs, but if high temperature seals were installed, it would remove the need to perform the time critical actions associated with restoration of seal cooling after it is lost.	Internal Events PRA Importance Review	$6,234,672	Yes	See Section F.6.7
11	Install Containment Combustible Gas Igniters	Early containment failure is a large contributor to the LERF release category. Although inerting containment in accident conditions could help prevent burns of combustible gases, a better solution is to install battery-backed igniters throughout upper dome of containment.	Internal Events PRA Importance Review	$4,651,776	Yes	See Section F.6.8

Table F.5-3
DCPP Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate[1]	Retained	Phase 1 Baseline Disposition
12	Improve Fire Barriers for ASW and CCW Equipment in the Cable Spreading Room	Currently, the dominant DCPP fire scenarios are estimated to be those cable spreading room fires that result in damage to the ASW and CCW controls such that the evacuation to the hot shutdown panel would be required to maintain the plant in a safe state. Credit is not taken for the existing fire detection and suppression equipment in the cable spreading room, which may overestimate the risk posed from fires in this room. However, plant risk could be further reduced by improving fire barriers on the ASW and CCW equipment located in the cable spreading room. If control of these two systems could be maintained within the MCR by preventing damage to these systems, the challenge to the operators would be reduced.	Fire Analysis Importance Review	$775,296	Yes	See Section F.6.9
13	Improve Cable Wrap for the PORVs in the Cable Spreading Room	Cable Spreading Room fire scenarios are large contributors to CDF due to fires that result in the spurious opening of one or more PORVs due to hot short conditions. These scenarios can lead to unisolated LOCAs that require feed and bleed for mitigation. Protecting the PORV cables is a potential means of eliminating the PORV LOCAs.	Fire Analysis Importance Review	$775,296	Yes	See Section F.6.10
14	Fully Automate Feed and Bleed Initiation	In some fire scenarios where MCR abandonment is required or when rapidly evolving scenarios overload operators with required tasks, automation of the feed and bleed action could improve its reliability.	Fire Analysis Importance Review, Seismic Analysis Importance Review	$11,435,616	No	Screened based on implementation cost greater than MACR. See Section F.7.2.1.2 for 95th percentile impact on Phase 1 screening.

Table F.5-3
DCPP Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate[(1)]	Retained	Phase 1 Baseline Disposition
15	Provide Hard Piped Connection between Fire Water and the Charging Pump Lube Oil Coolers and Remotely-Operated MOVs	For certain combinations of AC power division failures (especially fire events), the self-cooled charging pump could be unavailable and the remaining charging pump is vulnerable to loss of CCW events. Enhancing the connection between Fire Water and CCP lube oil cooling so that it can be aligned in a timely manner can prevent failure of the charging pumps and provide makeup for the subsequent low leakrate (21 gpm per pump, 84 gpm total) RCP seal LOCA (which accounts for 78 percent of all seal LOCAs). Use of a hard pipe connection with remotely-operated isolation MOVs should reduce operator response by decreasing manipulation time and eliminating the alignment action.	Fire Analysis Importance Review	$9,626,592	No	Screened based on implementation cost greater than MACR. See Section F.7.2.1.3 for 95th percentile impact on Phase 1 screening.
16	Install Automatic Suppression In Vertical Board 4 of the MCR	While automatic suppression systems are not assumed to prevent damage to the equipment associated with the fire initiator, automatic suppression could prevent propagation of the fire between power divisions. For MCR fires that start in Vertical Board 4, this capability could greatly reduce the risk of the fires.	Fire Analysis Importance Review	$3,944,318	Yes	See Section F.6.11
17	Install Alternate Power Connections to CCP 12	Providing CCP 12 with alternate power connections would ensure RCS makeup would be available whenever at least one division of emergency power is available (assuming the pump is available). Installation of local connections and breaker controls would allow the alternate power alignment to be completed in time to provide makeup for the subsequent low leakrate (21 gpm per pump, 84 gpm total) RCP seal LOCA (which accounts for 78 percent of all seal LOCAs).	Fire Analysis Importance Review	$5,184,792	Yes	See Section F.6.12

Table F.5-3
DCPP Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate[(1)]	Retained	Phase 1 Baseline Disposition
18	Seismically Qualified Alternate 480V AC EDG to Support Long Term AFW Operation and a Seismically Qualified 480V AC Self-Cooled PDP for RCS Makeup	For seismic events that fail the site's 4kV AC systems, an alternate EDG could be used to power a station battery charger for SG level instrumentation and AFW control. In addition, if power can rapidly be supplied to a 480V AC self-cooled PDP, a manually connected, long term primary side makeup source would be available to mitigate RCP seal leakage. The generator and pump would have to be stored in a seismically qualified area. This SAMA is geared towards mitigating the higher probability (low leakrate) RCP seal LOCA (21 gpm per pump, 84 gpm total), which accounts for 78 percent of all seal LOCAs.	Seismic Analysis Importance Review	$6,441,418	Yes	See Section F.6.13
19	Replace Critical Relays with High Seismic Capacity Relays	Relays in the emergency power circuit are assumed to be vulnerable to very high seismic activity, which can lead to interruptions in the availability of emergency 4kV AC power. Replacing the relays with designs that are more seismically durable could prevent relay faults due to very large seismic events.	Seismic Analysis Importance Review	$15,312,096	No	Screened based on implementation cost greater than MACR. See Section F.7.2.1.4 for 95th percentile impact on Phase 1 screening.
20	Use Alternate Signal (such as AMSAC) to De-energize the 480V AC Busses that Supply the Rod Drive Motor Generator Sets.	In the event that the MG set breakers do not trip in an ATWS, an alternate signal, such as an AMSAC signal, could be used to depower the 480V AC supply that powers the MG sets to ensure the control rod drive units are shut down. The 480V trip could be delayed so that it is only performed after 30 seconds with a valid ATWS signal.	Seismic Analysis Importance Review	$7,526,832	No	Screened based on implementation cost greater than MACR. See Section F.7.2.1.5 for 95th percentile impact on Phase 1 screening.

**Table F.5-3
DCPP Phase 1 SAMA List Summary**

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate(1)	Retained	Phase 1 Baseline Disposition
21	Provide a Portable Air Compressor to Pressurize IA Header	In the event that loss of offsite power fails the IA system, a portbale air compressor could be used to pressurize the IA header to support emergency actions in accident scenarios.				This SAMA was not used
22	Install a Redundant Actuation System for AFW	Failure of the SSPS system to actuate critical equipment followed by failure of the operators to manually start the systems can lead to core damage. Based on operator dependence issues, additional, manual recovery actions would provide limited benefit. Inclusion of a redundant means of actuating the AFW system on low SG level is a potential means of reducing the contribution of SSPS failures.	Seismic Analysis Importance Review	Not Required	Yes	Cannot be screened on cost or applicability to the plant. Retain for Phase 2 analysis (refer to Section F.6.14).
23	Reinforce SG and Associated RCS Piping Supports	Failure of the SGs in a seismic event can potentially overpressurize that containment due to the large steam volume that would be expelled into the reactor building from the primary and/or secondary sides. Depending on the mode of failure, mitigation of the SG failure is also challenging and the PRA assumes that SG failures result in core damage. Strengthening the SG and associated RCS piping supports so that they would be expected to remain intact for seismic events with peak accelerations of 2.0g to 2.5g would address some of the larger DCPP seismic contributors.	Seismic Analysis Importance Review	$83,990,400	No	Screened based on implementation cost greater than MACR.

Table F.5-3
DCPP Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate[1]	Retained	Phase 1 Baseline Disposition
24	Prevent Clearing of RCS Cold Leg Water Seals	This SAMA models the procedure change that would preclude the operators from clearing the water seals in the RCS cold legs after core damage. If the loop seals are cleared there is an unobstructed flowpath for hot gases to flow from the damaged vessel through the steam generator tubes increasing the likelihood of an induced steam generator tube rupture.	Internal Events PRA Importance Review	$50,000	Yes	See Section F.6.15
25	Fill or Maintain Filled the Steam Generators to Scrub Fission Products	This SAMA makes a procedure change that directs operators to fill or maintain filled the steam generators just prior to core damage to provide mechanical scrubbing of fission products.	Internal Events PRA Importance Review	$50,000	Yes	See Section F.6.16

Notes:

(1) Cost estimates are on a per unit basis

Table F.6-1
DCPP Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
2	Automate Swap to Recirculation	The operators are well trained on the action to transition the RCS injection systems to recirculation mode, but automating the process will further improve reliability and reduce the contribution of this action to core damage scenarios.	Internal Events PRA Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.
3	Alternate DC Generator	In order to mitigate DC system failures, an alternate DC generator could be used to directly power a bus (bypasses charger faults) or directly power critical loads (bypasses distribution failures). The generator should be stored in a seismically qualified area so that it would potentially be available to respond in seismic scenarios.	Internal Events PRA Importance Review, Seismic Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.
5	Use an Alternate EDG to Support Long Term AFW Operation and a 480V AC Self-Cooled PDP for Primary Side Makeup	A low costly SBO mitigation strategy is to use a small, alternate EDG to power a station battery charger for level instrumentation and AFW control. In addition, if power can be supplied to a 480V AC self-cooled positive displacement pump, primary makeup could be maintained to mitigate a seal LOCA. This SAMA is geared towards mitigating the higher probability (low leakrate) RCP seal LOCA (21 gpm per pump, 84 gpm total), which accounts for 78 percent of all seal LOCAs.	Internal Events PRA Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.
7	Replace or Modify the Battery Chargers to Operate Without the Batteries	Typically, battery chargers are not designed to support all DC demands without the batteries. If they can be replaced or modified so that they could do this, it would mitigate battery failure scenarios.	Internal Events PRA Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.

Table F.6-1
DCPP Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
8	Install an Additional Train of Switchgear Room HVAC	Alternate Switchgear Room cooling procedures already exist for DCPP, but the loss of room cooling is still an important issue. While costly, a potential means of reducing the HVAC failure contribution would be to install an independent train of HVAC.	Internal Events PRA Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.
9	Backup Air System for PORV PCV 474	Currently, loss of offsite power results in the loss of the IA system. Changing the air supply to PCV 474 (Pressurizer PORV) to a class I backup air supply via N2 bottles would prevent this and reduce the loss of IA contributions to core damage.	Internal Events PRA Importance Review, Seismic Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.
10	Install High Temperature RCP Seals	Mitigation strategies to supply alternate RCP seal cooling can reduce the risk of RCP seal LOCAs, but if high temperature seals were installed, it would remove the need to perform the time critical actions associated with restoration of seal cooling after it is lost.	Internal Events PRA Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.
11	Install Containment Combustible Gas Igniters	Early containment failure is a large contributor to the LERF release category. Although inerting containment in accident conditions could help prevent burns of combustible gases, a better solution is to install battery-backed igniters throughout upper dome of containment.	Internal Events PRA Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.

Table F.6-1
DCPP Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
12	Improve Fire Barriers for ASW and CCW Equipment in the Cable Spreading Room	Currently, the dominant DCPP fire scenarios are estimated to be those cable spreading room fires that result in damage to the ASW and CCW controls such that the evacuation to the hot shutdown panel would be required to maintain the plant in a safe state. Credit is not taken for the existing fire detection and suppression equipment in the cable spreading room, which may overestimate the risk posed from fires in this room. However, plant risk could be further reduced by improving fire barriers on the ASW and CCW equipment located in the cable spreading room. If control of these two systems could be maintained within the MCR by preventing damage to these systems, the challenge to the operators would be reduced.	Fire Analysis Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.
13	Improve Cable Wrap for the PORVs in the Cable Spreading Room	Cable Spreading Room fire scenarios are large contributors to CDF due to fires that result in the spurious opening of one or more PORVs due to hot short conditions. These scenarios can lead to unisolated LOCAs that require feed and bleed for mitigation. Protecting the PORV cables is a potential means of eliminating the PORV LOCAs.	Fire Analysis Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.
16	Install Automatic Suppression In Vertical Board 4 of the MCR	While automatic suppression systems are not assumed to prevent damage to the equipment associated with the fire initiator, automatic suppression could prevent propagation of the fire between power divisions. For MCR fires that start in Vertical Board 4, this capability could greatly reduce the risk of the fires.	Fire Analysis Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.

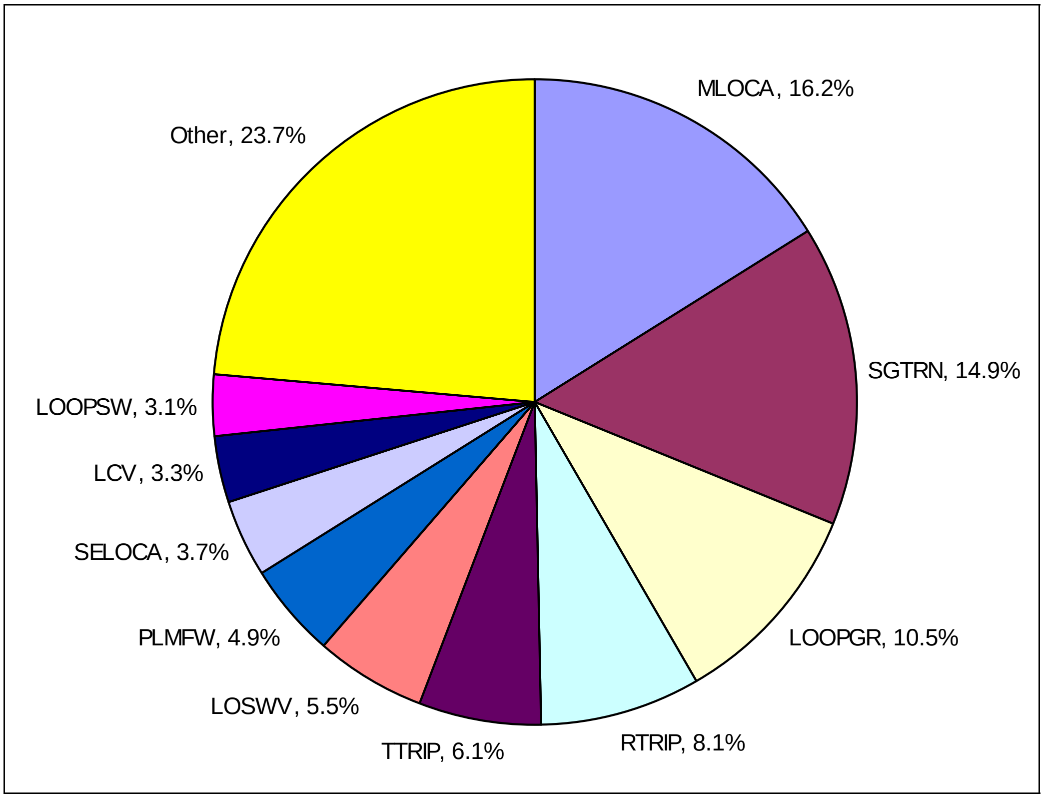
Table F.6-1
DCPP Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
17	Install Alternate Power Connections to CCP 12	Providing CCP 12 with alternate power connections would ensure RCS makeup would be available whenever at least one division of emergency power is available (assuming the pump is available). Installation of local connections and breaker controls would allow the alternate power alignment to be completed in time to provide makeup for the subsequent low leakrate (21 gpm per pump, 84 gpm total) RCP seal LOCA (which accounts for 78 percent of all seal LOCAs).	Fire Analysis Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.
18	Seismically Qualified Alternate 480V AC EDG to Support Long Term AFW Operation and a Seismically Qualified 480V AC Self-Cooled PDP for RCS Makeup	For seismic events that fail the site's 4kV AC systems, an alternate EDG could be used to power a station battery charger for SG level instrumentation and AFW control. In addition, if power can rapidly be supplied to a 480V AC self-cooled PDP, a manually connected, long term primary side makeup source would be available to mitigate RCP seal leakage. The generator and pump would have to be stored in a seismically qualified area. This SAMA is geared towards mitigating the higher probability (low leakrate) RCP seal LOCA (21 gpm per pump, 84 gpm total), which accounts for 78 percent of all seal LOCAs.	Seismic Analysis Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.
22	Install a Redundant Actuation System for AFW	Failure of the SSPS system to actuate critical equipment followed by failure of the operators to manually start the systems can lead to core damage. Based on operator dependence issues, additional, manual recovery actions would provide limited benefit. Inclusion of a redundant means of actuating the AFW system on low SG level is a potential means of reducing the contribution of SSPS failures.	Seismic Analysis Importance Review	Screened from analysis based on PRA insights as described in Section F.6.14.

Table F.6-1
DCPP Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
24	Prevent Clearing of RCS Cold Leg Water Seals	This SAMA models the procedure change that would preclude the operators from clearing the water seals in the RCS cold legs after core damage. If the loop seals are cleared there is an unobstructed flowpath for hot gases to flow from the damaged vessel through the steam generator tubes increasing the likelihood of an induced steam generator tube rupture.	Internal Events PRA Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.
25	Fill or Maintain Filled the Steam Generators to Scrub Fission Products	This SAMA makes a procedure change that directs operators to fill or maintain filled the steam generators just prior to core damage to provide mechanical scrubbing of fission products.	Internal Events PRA Importance Review	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.

F.10 FIGURES



Initiator	Description
MLOCA	MEDIUM LOCA
SGTRN	NON-OSOLATED SGTR FOR LEVEL 2
LOOPGR	LOSS OF OFFSITE POWER - GRID RELATED
RTRIP	REACTOR TRIP
TTRIP	TURBINE TRIP
LOSWV	LOSS OF SWITCHGEAR VENTILATION
PLMFW	PARTIAL LOSS OF MAIN FEEDWATER
SELOCA	RCP SEAL CATASTROPHIC SEAL FAILURE
LCV	LOSS OF CONDENSER VACUUM
LOOPSW	LOSS OF OFFSITE POWER - SEVERE WEATHER

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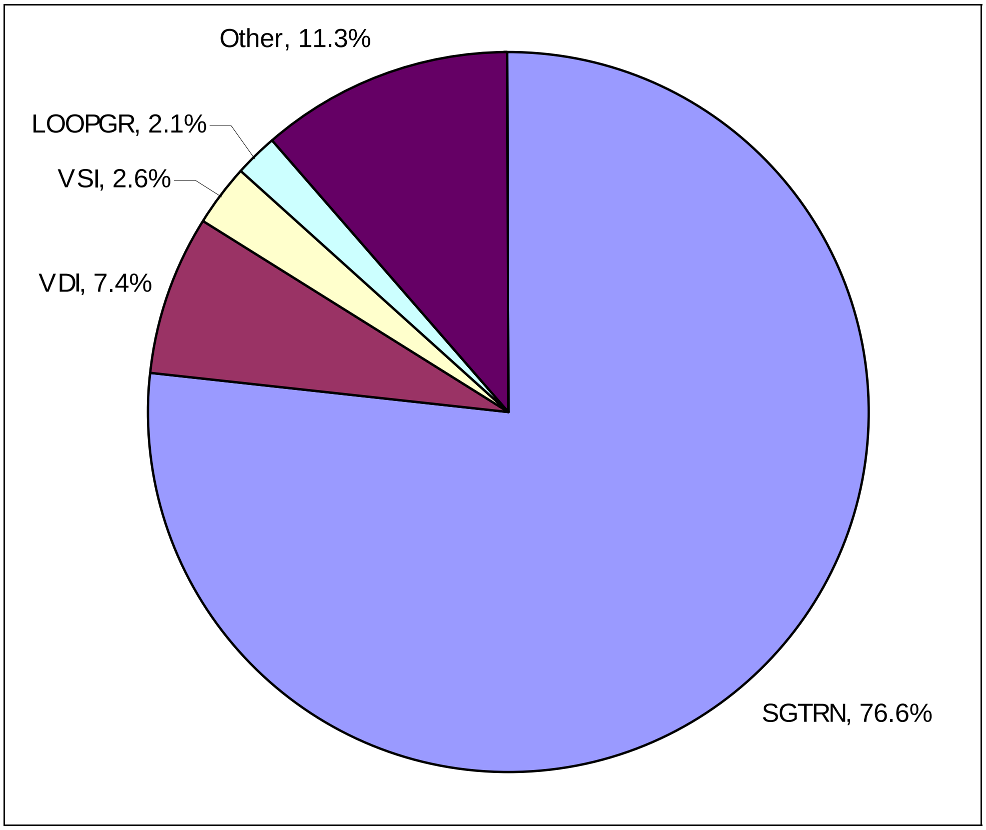
Figure F.2-1
DC01A Internal Contribution to CDF by Initiating Event



Initiator	Description
SGTRN	NON-OSOLATED SGTR FOR LEVEL 2
VDI	INTERF LOCA AT RHR PP DISCH 6/98 SAME
VSI	INTERFACING LOCA AT RHR PUMP SUCTION
LOOPGR	LOSS OF OFFSITE POWER - GRID RELATED

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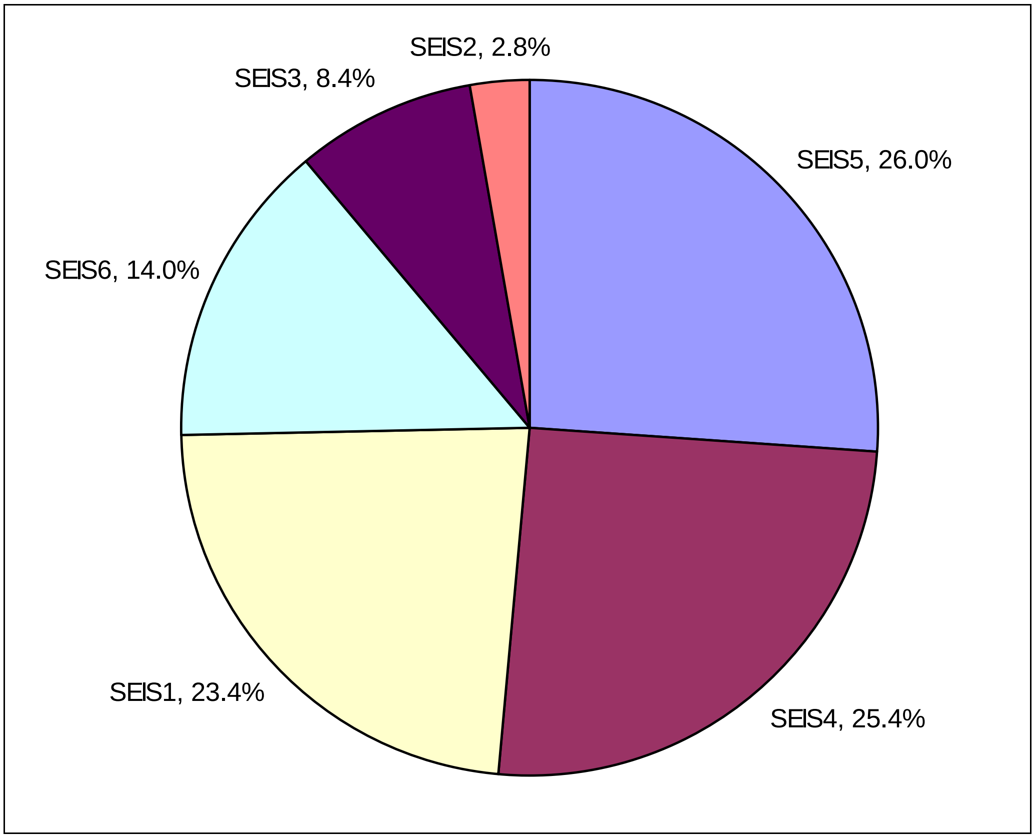
Figure F.2-2
DC01A Internal Contribution to LERF by Initiating Event



Initiator	Description
SEIS5	SEISMIC LEVEL 5
SEIS4	SEISMIC LEVEL 4
SEIS1	SEISMIC LEVEL 1
SEIS6	SEISMIC LEVEL 6
SEIS3	SEISMIC LEVEL 3
SEIS2	SEISMIC LEVEL 2

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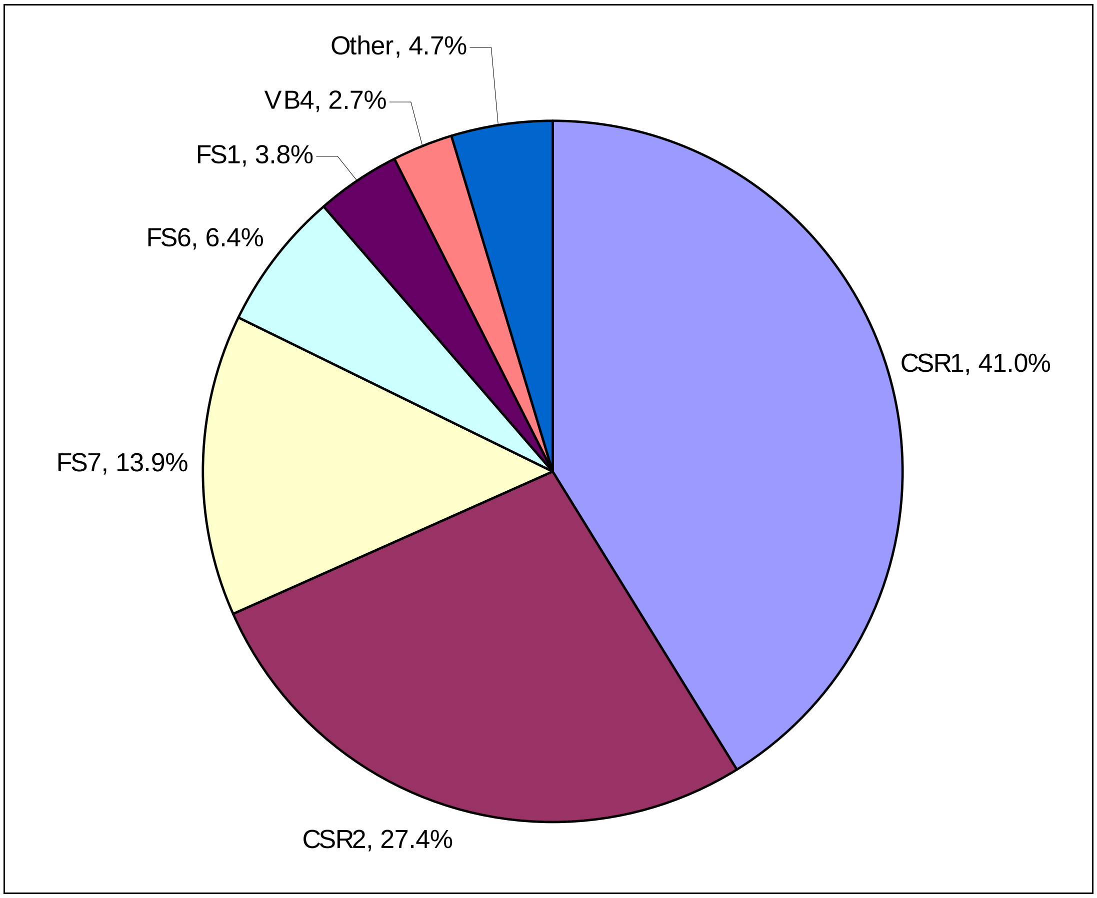
Figure F.2-3
DC01A Seismic Contribution to CDF by Initiating Event



Initiator	Description
CSR1	CSR FIRE 1 - LOSS OF ASW/CCW.
CSR2	CSR FIRE 2 - PORV INDUCED LOCA.
FS7	FS7: LOSS OF BUSES HG & HH
FS6	FS6: LOSS OF BUSES HF & HG
FS1	FS1: LOSS OF BOTH AFW PUMPS
VB4	CONTROL ROOM FIRE AT VB-4

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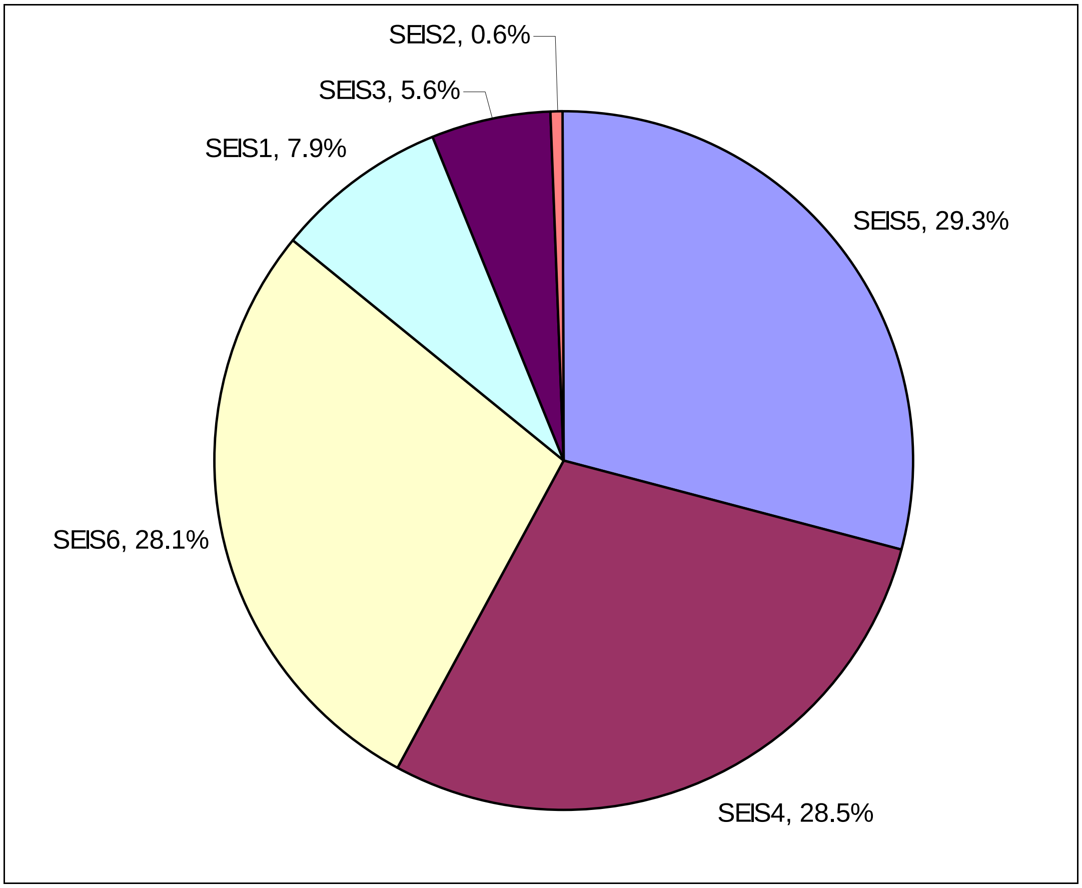
Figure F.2-4
DC01A Fire Contribution to CDF by Initiating Event



Initiator	Description
SEIS5	SEISMIC LEVEL 5
SEIS4	SEISMIC LEVEL 4
SEIS6	SEISMIC LEVEL 6
SEIS1	SEISMIC LEVEL 1
SEIS3	SEISMIC LEVEL 3
SEIS2	SEISMIC LEVEL 2

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Figure F.2-5
DC01A Seismic Contribution to LERF by Initiating Event

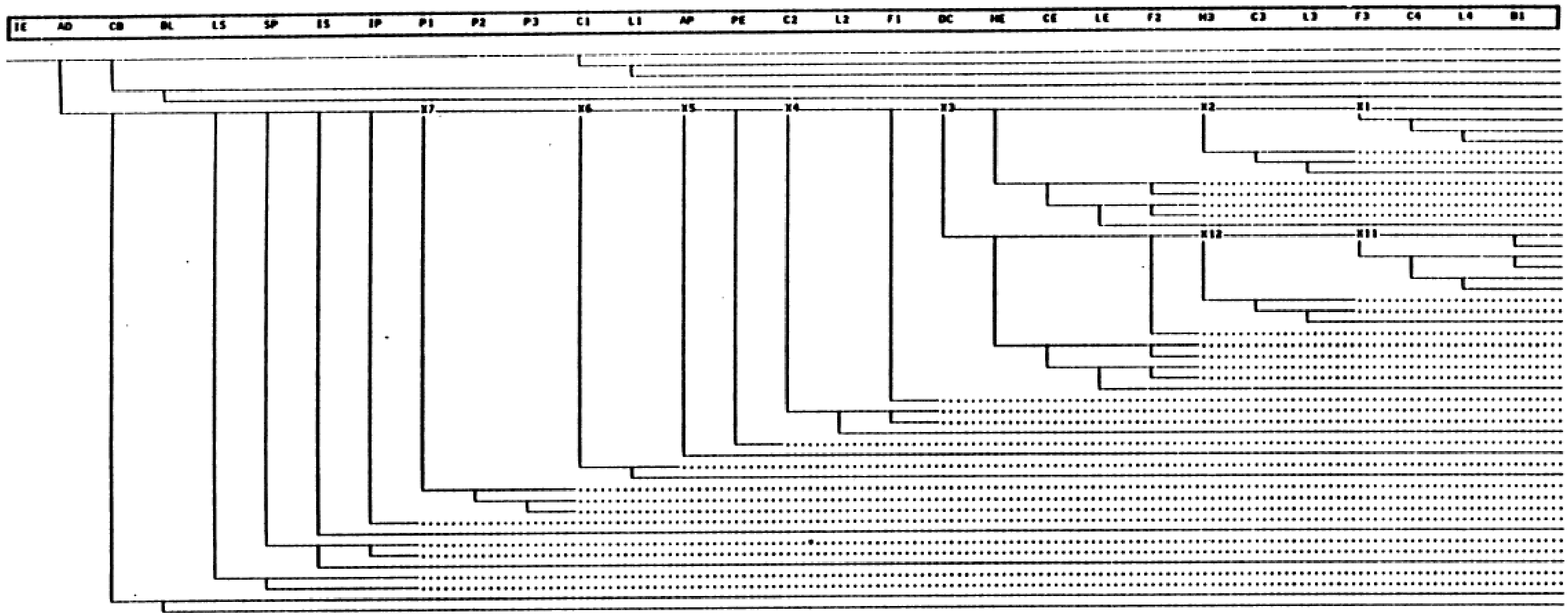

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Figure F.2-6
Containment Event Tree

Top Event	Failure Description	Accident Progression Phase
IE	Entry State	Damaged Core in Vessel
AD	Failure To Arrest Core Damage and Prevent Vessel Breach	
CB	Containment Bypass Prior to Core Damage	
BL	Large Bypass Prior to Core Damage	
LS	Induced PORV Failure	
SP	RCP Seal Cooling Unavailable	
IS	Induced Steam Generator Tube Rupture	
IP	Induced RCS Hot Leg or Surge Line Failure	
P1	RCS Pressure at Vessel Breach Exceeds 200 psia	
P2	RCS Pressure at Vessel Breach Exceeds 650 psia	
P3	RCS Pressure at Vessel Breach Exceeds 2000 psia	
C1	Containment Failure Prior to Vessel Breach	
L1	Large Containment Failure Prior to Vessel Breach	
AP	Containment is Failed by an In-Vessel Steam Explosion	Post-Vessel Breach and Early Containment Behavior
PE	High Pressure Melt Ejection	
C2	Containment Failure at Vessel Breach	
L2	Large Containment Failure at Vessel Breach	
F1	Containment Fan Coolers Inoperable After Vessel Breach	
DC	Debris Is Not Cooled	
HE	Hydrogen Burn Within 4 Hours of Vessel Breach	
CE	Containment Failure Due to Early Hydrogen Burn	
LE	Large Containment Failure From Early Burn	
F2	Containment Fan Coolers Fail After Early Burn or Debris Uncoolable	Long Term Containment Behavior
H3	Late Burn of Combustible Gases	
C3	Late Containment Failure Due to Burn	
L3	Large Late Containment Failure	
F3	Long Term Operation Failure of Containment Fan Coolers	
C4	Long Term Overpressurization	
L4	Large Long Term Containment Failure	
B1	Basemat Penetration	

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Figure F.2-7
Containment Event Tree Top Events

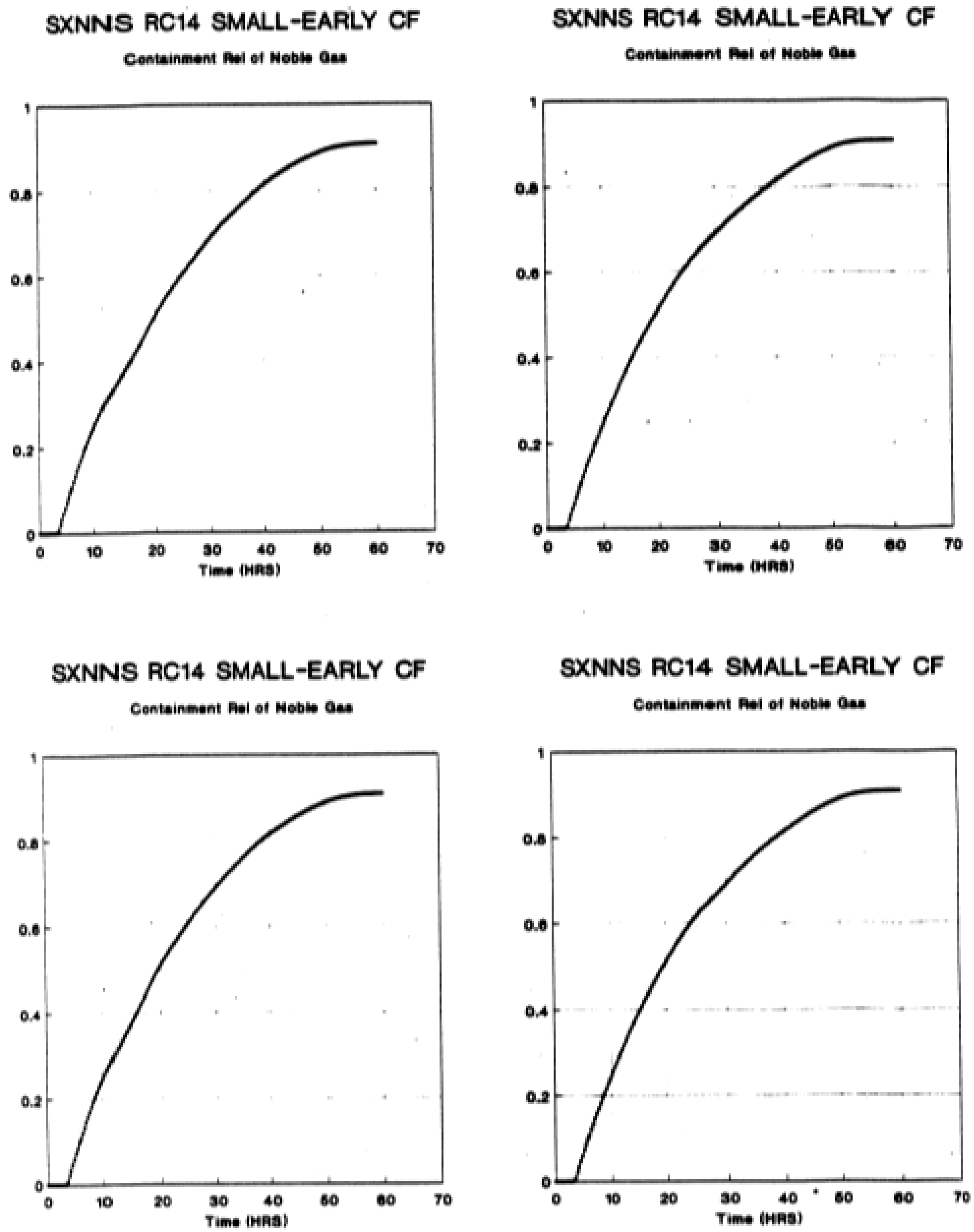

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Figure F.2-8
Small – Early Containment Release Response

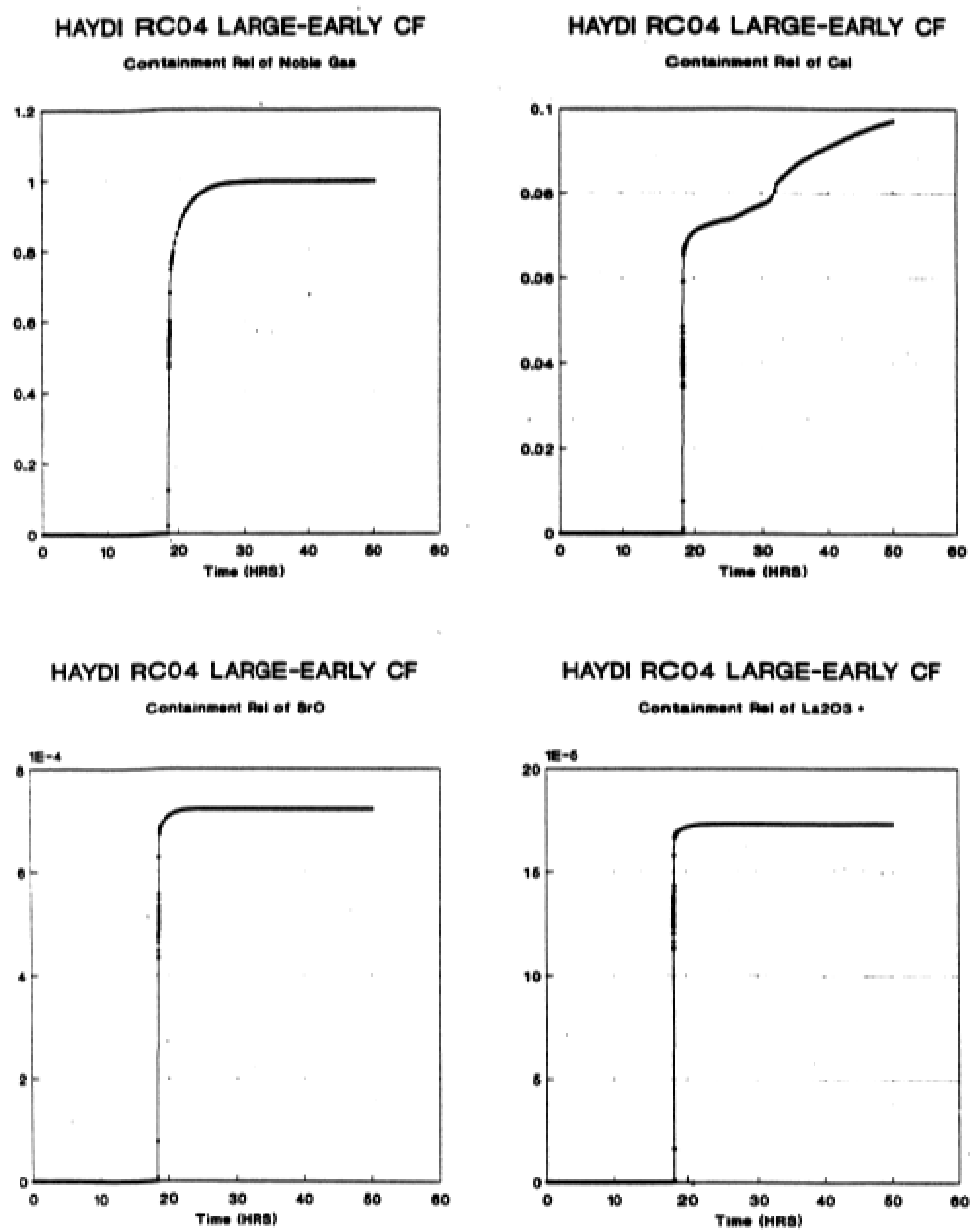

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Figure F.2-9
Large – Early Containment Release Response

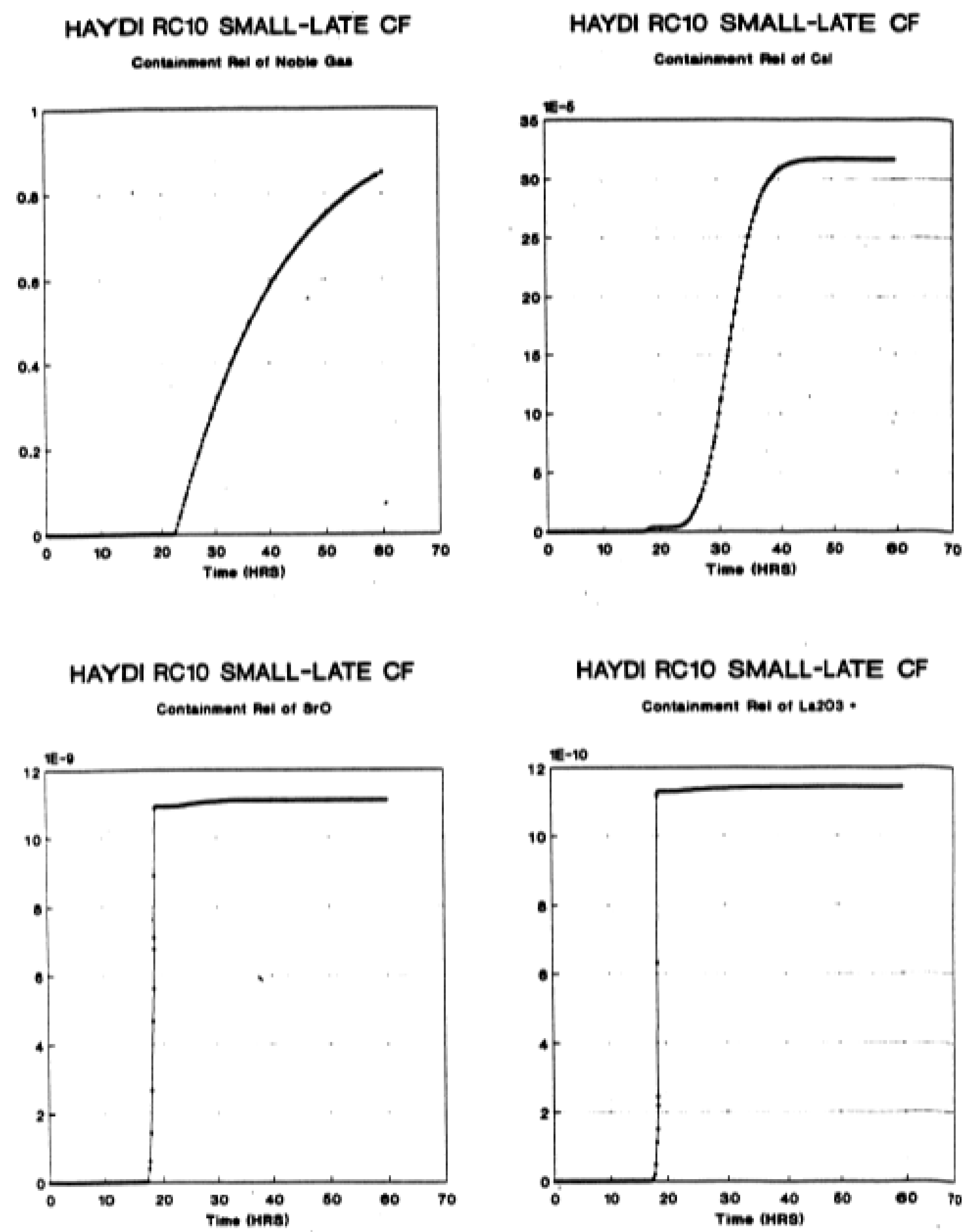

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Figure F.2-10
Small – Late Containment Release Response

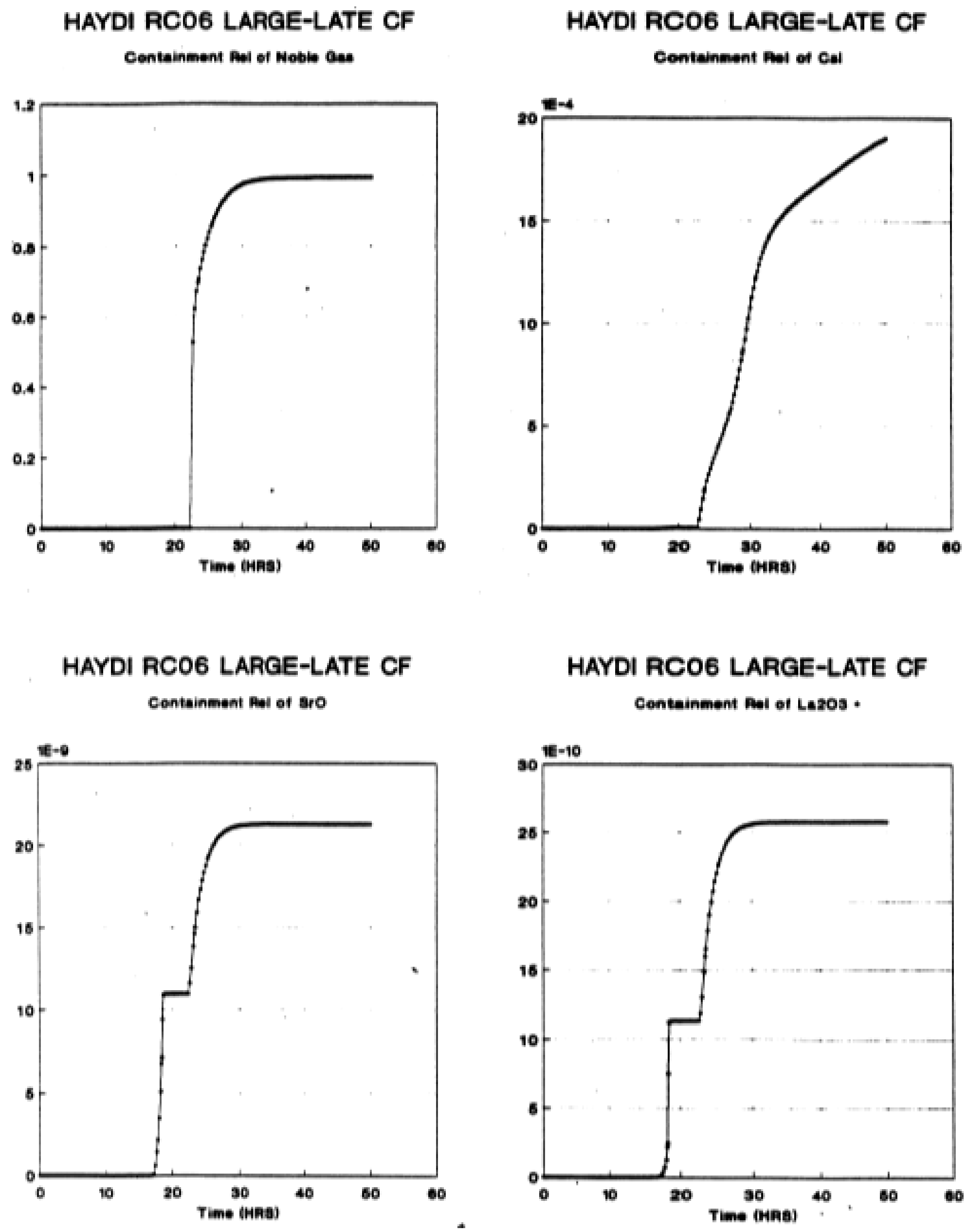

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Figure F.2-11
Large – Late Containment Release Response

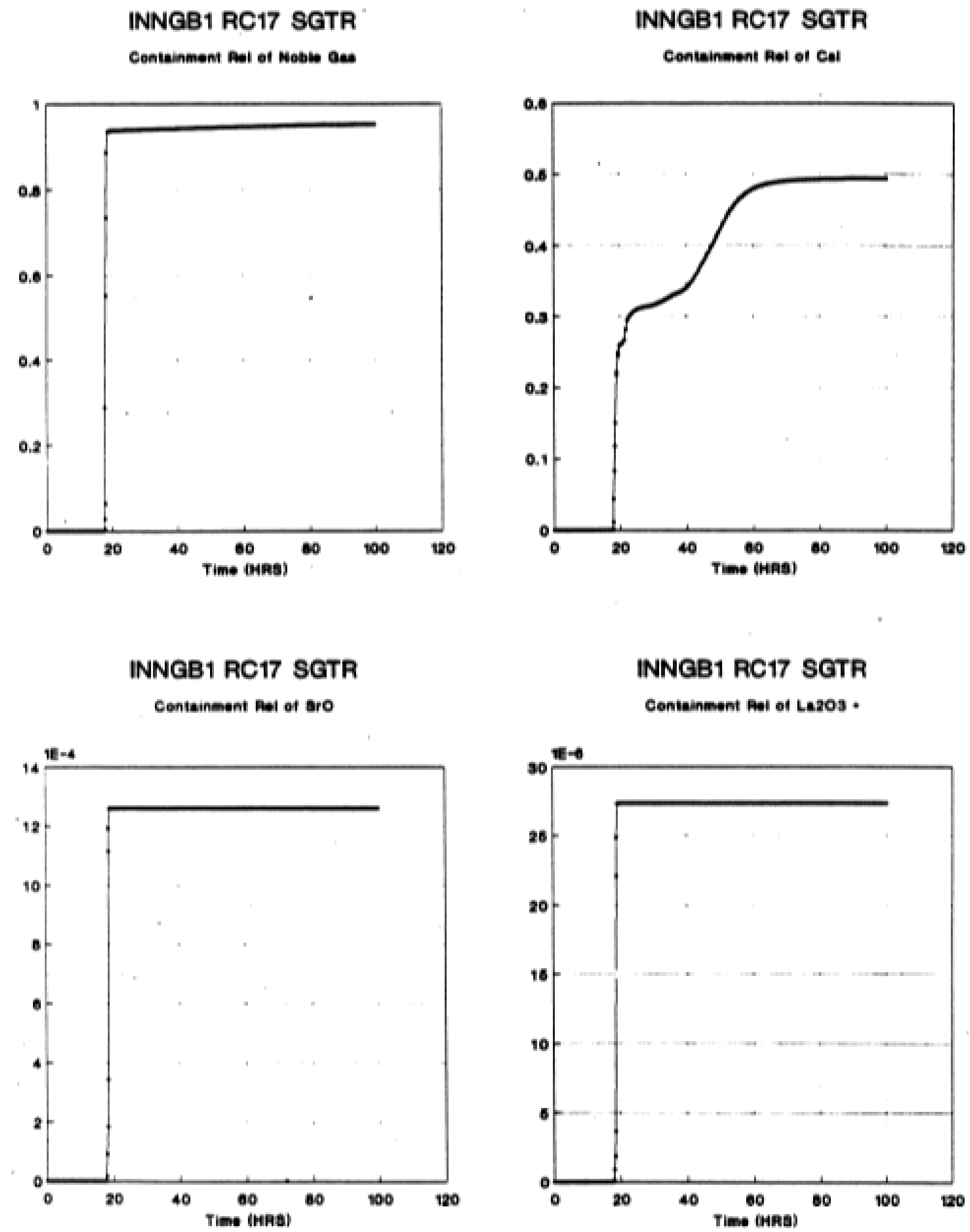

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Figure F.2-12
Containment Bypass Release Response

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
D	A	34	Internal flooding - NRC IN 98-31, SER 3-98, A0468801	AR A0468801 was written to document PG&E's evaluation of an event at WNP-2, where a fire system water hammer led to flooding of ECCS pump rooms. The evaluation was not complete by the time the 1997 PRA internal flood update was performed. This PG&E evaluation should be reviewed as part of the 1999/2000 PRA update to see if any assumptions or new insights need to be added to the PRA internal flooding analysis.	This will be considered in the updating of the Internal Flooding PRA.	None. No direct impact on current model anticipated.
D	A	35	Human actions for internal flooding in intake structure	The loss of ASW due to internal flooding initiating event was created in F.4 Revision 1, and uses two human actions in basic events FLHE1 AND FLHE2. THese basic events represent failure to isolate an ASW pipe rupture (0.1 used) and piping leaks/expansion joint failure, which uses the human action ZHESV2 as an reasonable representation of the value. As part of the next human actions update, consideration should be given to developing the human actions for basic events FLHE1 and FLHE2.	The HEPS were re-quantifed in the HRA calculator as part of G.2 Rev 4. They will be incoporated in the next update of the internal flooding analysis.	None. Current model is conservative and no impact on SAMA application

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
D	A	56	Expansion joints	Need to add expansion join failures to various system models and maybe some of the system initiators. Expansion joints were added in the intake flooding initiator in winter of 1999. Expansion joints appear in various modeled systems. There is the ASW system (Calc. D.2.6), and the CCWHE (Calc. D.2.7), and there maybe more.	Expansion joints were included as a contributor to the unavailability of ASW and CCW systems. Need to consider expansion in the circulating water system in the updating of Internal Flooding analysis.	Turbine Building flood scenarios not significant contributors to risk. No impact on SAMA application.
D	A	309	ST - 3 - Flooding Treats Doors Deterministicall y "C"	The flooding analysis treats failure of doors deterministically, not probabilistically. In a PRA, a probabilistic assessment of failure of flood barriers should be included. That is, the probabilities that various flood barriers may fail should be included in the overall assessment of flooding-induced core damage scenarios.	Consider the effects of failure of flood barriers when Internal Flooding analysis is updated.	The incremental impact of the additional failure mechanisms is not likely to be large unless a new propagation pathway is identified. Insignificant impact on flooding risk is expected and no impact on SAMA application.
D	A	602	ASME SRs IF-B1b, IF-C5, IF-C5a	Table F.4-2 [B3] includes a screening process. However the general screening criteria used are not well defined and justified and in some cases include judgmental credit for isolation of sources before damage/ propagation can occur and /or drainage capacity. The containment is screened out on the basis that it is designed for LOCA and high energy line breaks in containment (Section F.4.3). **Recommendation for improvement to meet**	Screening criteria from the ASME PRA Standard will be adopted in the update of Internal Flooding analysis.	Flooding events are not significant contributors to CDF. Impact on results of the SAMA identification will be negligible.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				PRA Standard Recommend defining a set of qualitative and quantitative screening criteria consistent with the ASME standard and indicating for each specific flood area which particular criteria is applicable.		
D	A	603	ASME SRs IF-C1, IF-C3b	Table F.4-2 identifies the flood propagation paths from the source area to an adjacent area (but no further) Section F.4.3.2 provides a general discussion Section F.4.3.2 provides a good general description for each building (turbine, intake, auxiliary and fuel handling) of the flood propagation pathways to their ultimate point of accumulation Did not see any reference to analysis of structural failures in the analysis although this probably because the potential for significant flood accumulation in most cases is minimal given the plant design The only evidence of random barrier element failures being considered is in respect of the ASW room drain check valves. **Recommendation for improvement to meet PRA Standard** In flood area information sheets (see IF-A4) document potential propagation paths thru cable penetrations as well as doors and HVAC ducts.	Only areas where significant accumulation leading to structural failure of barrier elements are the SI Pump room and Charging Pump Room. In these cases one can assume that barrier failures may lead to damage in adjacent areas where appropriate.	Those flooding events are not significant contributors to CDF. Impact on results of the SAMA identification will be negligible.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				Review flood analysis to identify cases where flood accumulation may occur (or has not been ruled out) and determine if consequences of barrier element challenges (e.g. doors or penetration seals) may result in a plant impact which has not been addressed in the current flood analysis. If so perform engineering analysis to determine if the barrier element will withstand the loading Performing the above will satisfy the Cat II requirements. In order to satisfy Cat III requirements the random failure of any barrier elements identified as being challenged and with significant consequences of failure will need to be addressed. (See Westinghouse F&O type C) For area which may be susceptible to high energy line breaks determine if barriers and barrier elements will be challenged by over pressure and determine consequences of failure.		

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
D	A	604	ASME SRs IF-C2a, IF-C6	Automatic or operator responses to terminate floods are summarized in the discussion of flood location and scenario evaluations provided in section F.4.3.2 Table F4 Scenarios 45, 46, 53, 54 appears to credit manual action for isolation in order to screen (although it is not clear whether the consequences of non isolation are significant). No discussion of flood indication, timing or means of isolation is provided. **Recommendation for improvement to meet PRA Standard** Where such features form part of the argument for screening or evaluating flood scenarios this information should be provided. Specifically recommend evaluating the reliability of actions credited in the scenarios 45, 46, 53, 54, 69, 83 and 84.	Consequences of non isolation in a timely manner were found to be potentially significant for SCW, CCW, RWST supply floods and AFW pump room floods in terms of controlling the potential for flood propagation or gross system impact. A screening analysis is proposed which does not credit isolation, except in the case of the SCW where the flooding rate relative to the volume required to cause damage was judged to be such that the time available would be many hours.	Flooding events are not significant contributors to CDF. Impact on conclusions of the current application will be negligible.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
D	A	605	ASME SR IF-C3	Equipment susceptibility to various types of flood hazard are identified in table F.2-12 of the original DCPP flood PRA. In summary this table indicates that all electrical components except cables are assumed to be susceptible to flood accumulation and spray. High energy jet impingement may cause damage to all electrical components including cables. No reference to junction box qualification/damage is given and the treatment needs to be checked. It is not clear that high energy line break effects have been considered in the Revision 1 update. **Recommendation for improvement to meet PRA Standard** Need to include potential damage to junction boxes treatment due to spray and submergence.	Impact of high/moderate energy line breaks (HELB/MELB) need to be considered for Capability Category II. An update of the Internal Flooding Analyses should evaluate and document the impact of HELB/MELB.	Flooding events are not significant contributors to CDF. Impact on conclusions of the current application will be negligible.
D	A	606	ASME SR IF-C3c	The results of engineering calculations of maximum flood heights reported in DCM T-20 (see table F.4.4) are used in the study. For example a maximum flood height of 3" is cited as the reason for lack of flood propagation from the AFW TDP pump room to the AFW MDP pump rooms. When this reference was reviewed the calculation referred to was not apparent. **Recommendation for improvement to meet PRA Standard** Need to identify location of flooding calculations relied upon in the analysis and review underlying basis to ensure consistency with PRA requirements (e.g. no restrictions on maximum crack size or assumptions about isolation within specific time)	An update of the Internal Flooding Analysis should determine the applicability of design calculations cited in the existing Internal Flooding study.	Documentation issue. No impact on SAMA application.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
D	A	607	ASME SR IF-C4	Flood scenario development is generally accomplished in section F4.5.1. However it is not clear the analysis has recognized the consequences of flood isolation on system availability That is isolation of an AFW system flood may require the CST source to all pumps to be isolated depending upon (the break location). Isolation of a CCW flood may require partial isolation of the CCW system **Recommendation for improvement to meet PRA Standard** Screening analyses proposed which does address impact of isolation of flood source. Further detailed analyses may be needed if this conservative analysis shows high risk contribution.	The affected Internal Events analysis is conservative.	No impact on the results of SAMA identification.
D	A	608	ASME SR IF-C5a	It appears that DCPP analysis (Table F.4-2 item 23) credits isolation of a large turbine building flood prior to propagation to the DG corridor or the fuel oil pump room vaults via drains, and the 12kV room due to the automatic condenser mitigating features. This qualitative argument is used to screen out all propagation scenarios from the turbine building. **Recommendation for improvement to meet PRA Standard** Further examination of the reliability of the isolation system, the timing available for operator action, the integrity and reliability of the doors and drain check valves which protect the EDG rooms, the fuel oil pump vaults and the 12kV SWGR room as well as any drainage paths to the outside, is warranted in order to	An update of the Internal Flooding Analysis will re-examine the Turbine Building flood scenario(s).	No impact on the conclusion of the SAMA evaluation since the identified SAMAs #4 and #5 are associated with alternative onsite power source.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				screen this scenario (Although extremely unlikely this scenario could lead to a loss of the EDGs and loss of offsite power).		
F	A	320	Missing human action to line up SUT21 after failure of SUT11	The fault tree for top event OG takes credit for the Unit 2 transformer after the failure of SUT11. However, when this was put into the model, an HEP was not added for this. Probably because at first it was just being added to the model for planned manitenace on SUT11, but was expanded to failure of SUT11.	Including HEP for switching to Unit 2 SUT on loss of SUT11 has a very small impact on the unavailability of power from the 230kV offsite grid.	No impact on the conclusion of SAMA identification due to the very small impact on the unavailability of power from the 230kV offsite grid and on the CDF/LERF and the identified SAMAs #4 and #5 are associated with alternative onsite power source.
F	A	394	Hard coded conditional HEP in top event MU	Originally, in the model there was one HEP for the operators to makeup to the RWST in the general transient tree. During the HEP dependency study it was noticed that the HEP was used even if the operators had failed to swap over to recirculation cooling. As a work around for this, a conditional probability of 0.1 was used. A new HEP needs to be developed for this situation that is more realistic.	A new conditional prob of 0.5 was used in sensitivity study.	No impact on the conclusion of the SAMA evaluation since the identified SAMA #2 is associated with automatic switchover to sump recirculation.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
F	A	407	HEP ZHEBC1 has procedure steps different from execution procedure.	During the H.3 Rev. 2 procedure review, it was noticed that HEP ZHEBC1 execution steps differed from the current revision of J-9:II (Rev.14). Steps have been deleted and added to the procedure since the HEP analysis. For Calc Files G.1 and G.2 update, this should be reviewed.	The operator action (HEP of ZHEBC1) is a very small contributor to the unavailability of the long term DC power supply.	No impact on the conclusion of the SAMA evaluation since the identified SAMA #3 is associated with the DC Power.
F	A	411	ZHEAW2 needs updating	ZHEAW2 needs to be updated by including new procedure steps from OP D-1:V. The current Pexe in ZHEAW2 does not include opening MU-284. 284 is now a normally closed valve and must be opened prior to supplying AFW with RWR.	This has a very slight impact (small increase) on HEP.	Insignificant impact on the conclusion of the SAMA identification process due to the very small impact on the unavailability the AFW system and CDF/LERF..
F	A	429	Include Manipulation Time in HRA calculator Timing Analyses	Currently, G.2 Rev. 5 is inconsistent in its description of timing (I.E. the scenario description form indicates a Tsw that is different than the time window form.). In addition, the Time Window does not indicate a manipulation time whereas the scenario description indicates a manipulation time. For the determination of low dependence, medium dependence etc. this is not a concern since the available time window remains the same. However, with the addition of a dependency module in the HRA calculator, the inclusion of a manipulation time in the Time Window form may become important.	Include manipulation time in Time Window Tw. HRA issue.	This is being addressed in the HRA gap closure project. Inclusion of manipulation time in the HRA calculator will not impact the SAMA application.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				Action: Include manipulation time in Time Window form for the HRA calculator and adjust Tsw accordingly.		
F	A	430	HRA assumption for control staffing has changed	During interviews with operations personnel for the fire HRA, the control room staffing arrangement was brought up. Since the HRA update, the makeup of operators and SROs in the control room has changed. The position of Shift Engineer is now called the Work Control Shift Foreman (WCSFM) and that person now sits in the 119' turbine building area. Also, the two SCOs (one for each unit) are also located outside of the control room. These relocated Ops personnel can and will still respond to an accident situation. This may effect the assumptions in the HRA concerning cognitive and execution recoveries. During the next HRA update, investigate whether any of the DCPP HEPs will be affected by this staffing change.	Investigate impact of CR staffing change on HRA. HRA issue.	Despite ex-control room locations for operations personnel, they will be available during an accident to assist control room staff with diagnosis and performance of credited actions. Will not impact SAMA.
F	A	448	ZHEPR3 assumed time window of 1 hour	HFE ZHEPR3, Operators fail to close PORV Block Valve within 1 hr. The time window for this HFE was changed from 4 minutes in G.2 Rev.3 (ZHEPR2 - isolate PORV after reactor trip, prior to SI) to 1 hour in revision 5. The basis for the 1 hour criteria is not clearly spelled out anywhere in the PRA documentation.	Determine basis for 1 hour time window for ZHEPR3.	Documentation issue. No impact on SAMA application.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
F	A	704	ASME SR HR-G2:(2)	There are also other actions that were assumed to have negligible HEPs for the cognitive contribution and were not evaluated for cognitive errors (there are a total of 15 actions which have zero values in Table 1 for the human cognitive response probability; e.g. ZHEOR1 for SGTR cooldown and depressurization). This review does not accept the assertion that these actions can be assigned zero cognitive error probabilities.	DCPP HEPs are being reviewed as part of the internal PRA gap closure process.	The gap closure process may result in a change in HEP values. However, previous sensitivities performed on this set of HEPs as part of ECCS AOT LAR show that the impact on CDF is small.
F	A	707	ASME SR HR-G3:(1)	Due to the short time window available for cognitive diagnosis and decision-making (excluding cue time, any other delay time, and manipulation time), some actions may be significantly influenced by the PSF for "Time" (e.g., ZHERE5, ZHEPR1, ZHEOE1, ZHERF2, of the 10 sampled are of this type) These actions were evaluated using the CBDT approach only. For actions evaluated using the CBDT, the PSF for “Time” is accounted for only in the assignment of the level of dependency for recovery. For the evaluation of the initial errors, however, the PSF for “Time” (which may contribute to the occurrence of error due to the time pressure) is not accounted for in the CBDT tree branches.	DCPP HEPs are being reviewed as part of the internal PRA gap closure process.	The gap closure process may result in a change in HEP values. However, previous sensitivities performed on this set of HEPs as part of ECCS AOT LAR show that the impact on CDF is small.
F	A	709	ASME SR HR-G3:(2)	Section 5.3 on Page 19 states that “single” procedure should be selected for PCE but this seems inconsistent with EPRI guidance. (see actions ZHEPR1, ZHERF2,).	DCPP HEPs are being reviewed as part of the internal PRA gap closure process.	The impact to the HEP as a result of a change in Pce to "multiple" procedures results in a small increase in HEP value. This will have only a small impact on CDF.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
F	A	712	ASME SR HR-G3:(2)	Regarding Assumption 7 in Section 4.1 on Page 4, not all procedures use the “Response Not Obtained” format so it is unclear if the THERP tables used are correctly adjusted for all actions. For example, Step 3.h in Appendix B of Procedure OP AP-11 was treated in the analysis of the execution error for ZHECC1 (CCW heat load reduction) as if the procedure is in a columnar or “Response/Response Not Obtained” format, while this procedure is not written in this format. Another example is the annunciator response procedure used for the analysis of ZHECV1 (Control room ventilation recovery).	Actions important to risk typically involve procedures that are in a RNO format (All EOPs except for some appendices). ZHECC1 and ZHECV1 use Swain's table 20-7 which is used for narrative style procedures not RNO procedures.	Does not impact SAMA or any other application.
F	A	713	ASME SR HR-G3:(2)	For Modeling Convention 6 in Section 4.3.4 on Page 13, the reviewers do not believe that NUREG/CR-1278 intended that the first 10 steps of a long list can be assumed to be from a short list. (e.g., in the analysis of ZHERF2).	DCPP HEPs are being reviewed as part of the internal PRA gap closure process.	The use of a long list assumptions increases the HEP by slightly more than a factor of 2. This increase in HEP will not change results of SAMA conclusions.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
F	A	727	ASME SR HR-G7:(2)	The dependence analysis documentation suggests that there was a general assumption that if actions are directed by procedures with different numbers they can be considered independent. This is questionable. Other factors, such as time required, increased stress, availability of resources, and common instrumentation, can lead to dependencies between actions. Such dependencies governed by time are noted in the HRA methodology write-up.	DCPP HEPs are being reviewed as part of the internal PRA gap closure process.	Important sequences that contain multiple operator actions were reviewed in the DCPP HRA dependency analysis. The only identified combinations that were screened for this reason involves seismically induced failures of the CST (AW) and subsequent failures to either initiate feed and bleed (OB) or cold leg recirculation following successful feed and bleed (RF). This issue did not prevent identifying HFEs important to the SAMA; BO and RF have been identified based on their importance.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
F	A	728	ASME SR HR-G7:(2)	In some sequences, the presence of an intervening successful action (i.e. in the same sequence) can be used to dismiss actions failed in the same sequence as being only weakly dependent. Successful actions were not considered in the dependence review.	Not crediting successful intervening actions is conservative. Disposition of this issue will not adversely affect the results of this application.	Addressing this issue would potentially reduce importance of impacted HEPs. Impact of this would be minor since only HEPs with modeled dependency would be affected and then only slightly.
F	A	731	ASME SR HR-G7:(2)	For one selected sequence involving ZHEOE1, the analysis asserts that the action quantification analysis itself (using CBDT) adequately considers dependence with preceding actions in the sequence. This is not correct. Another example of a need to carefully evaluate the dependence on preceding actions in specific sequences is ZHEMU3.	DCPP HEPs are being reviewed as part of the internal PRA gap closure process.	An increase in the dependency between ZHEOE1/ZHEMU3 and preceding HFE failures would increase the importance of these sequences. This corresponding increase in CDF would be small since the current sequence contributions are low and would not be increased significantly by incorporation of dependence.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
F	A	732	ASME SR HR-H2:(1)	For the analysis of recovery actions (e.g., in the case of ZHECT1), it is unclear if credit can be taken, when the procedural guidance referenced is not sufficiently detailed to determine the operator's execution steps. Failure mechanism PCF may better be evaluated as item (g) 6E-2, rather than (a) negligible.	DCPP HEPs are being reviewed as part of the internal PRA gap closure process.	Proceduralized RNO directs investigation of differential/overcurrent relay issues. Given skill of craft, this direction is sufficiently detailed given cue (blue lights on CR panels).
F	A	733	ASME SR HR-H2:(1)	The action contained in recovery split fraction RE6A is mentioned in the dependency analysis but is not included in summary Table 1	DCPP HEPs are being reviewed as part of the internal PRA gap closure process.	Documentation issue. Dependency is modeled. No impact on SAMA application.
G	A	808	ASME SR LE-F2	LE-C10 is met at Capability Category I. The Level 2 re-peer reviewers noted a lack of evaluation of impact of key sources of uncertainty on the Level 2 LERF model. The re-peer report discusses a number of potential sources of uncertainty and impacts. For most PRA applications, it is not likely that such issues will affect LERF insights.	A formal evaluation of uncertainties in the LERF model has not been performed.	Not significant. Given the conservative nature of the approach used, formal consideration of uncertainties in the LERF modeling has no significant impact on the conclusion of SAMA identification process.

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G	A	811	ASME SR LE-G4	LE-G4 is not met. Basis is the Level 2 re-peer reviewer's assessment. Consideration should be given to developing the recommended evaluation of Key Assumptions and Key Sources of Uncertainty for the LERF model.	A formal evaluation of uncertainties in the LERF model has not been performed.	Not significant. Given the conservative nature of the approach used, formal consideration of uncertainties in the LERF modeling has no significant impact on the conclusion of the SAMA identification process.
G	A	812	ASME SR LE-G5	An assessment of limitations of the LERF model that might impact applications has not been developed.	A formal assessment of the limitation of the LERF model and the evaluation of uncertainties in the LERF model has not been performed.	Not significant. Given the conservative nature of the approach used, formal consideration of uncertainties in the LERF modeling has no significant impact on the conclusion of the SAMA identification process.
H	A	176	Seismic trip and PORV challenge	In revision 2 of calculation file F.6, the assumption that there was a PORV challange on every seismic initiating event was removed. This was because in most cases, the plant had already tripped from the seismic event (via seismic trip) and did not experience a load rejection when 500 kV was lost. The first item is that this assumes the seismic trip works successfully all the time. To be more correct, the	Modeling PORV challenge due to seismic induced LOSP has insignificant impact on the seismic induced CDF/LERF.	None. Insignificant impact on CDF/LERF.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				seismic trip should be added to the model and than the effect of the seismic trip can be evaluated probabilistically. Second item is the seisic trip has a setpoint of about 0.3 G's which is about 2/3's the way through the first seismic initiator (which goes to 0.53). This would imply that below 0.35 there sould be a PORV challange, if 500 kV was lost (which is not yet modeled). To better model this SEIS1 initiator should be changed to 0.4, and the details of the 500 kV and seismic trip should be modeled. Note RISKMAN is limited to only six accelleration levels, so this would require re-djusting the exist boundary between SEIS1 and SEIS2. Also note this corressponds to the DDE earthquake, which was the safe shutdown earthquake prior to the HOSGRI upgrades which put the SSE TO 0.75 G's. 12/19/02 EGD also note we do not model a PORV challenge on seismically induced LOSP, which should be adequate for SEIS 2 through 6 due to seismic trip, but maybe a noticable contributor in SEIS1.		

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
H	A	265	Address anchorage of relay panels in cable spreading rooms	NRC letter dated 12/4/97 informed DCPP that the intent of GL 88-20, supplement 4, had been met. The attachment to the NRC Report was a consultant's report entitled, "Technical Evaluation Report On The Submittal-Onlu Review Of The Diablo Canyon Power Plant (Units 1 And 2) Individual Plant Examination Of External Events," dated September, 1997. On page 28 of the consultant's report, they state in (B)(1) "..it is unclear if the licensee performed an analysis of the anchorage of relay panels within the cable spreading room." The concern is whether this equipment is a seismic induced hazard. Please address this issue and reference documentation.	To confirm that an analysis had been performed of the anchorage of relay panels within the cable spreading room.	This is a documentation issue and no impact on the SAMA application.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
H	A	271	Address potential for D/G lockout from cardox	NRC letter dated 12/4/97 informed DCPP that the intent of GL 88-20, Supplement 4, had been met. The attachment to the NRC Report was a consultant's report entitled, "Technical Evaluation Report On The Submittal-Onlu Review Of The Diablo Canyon Power Plant (Units 1 And 2) Individual Plant Examination Of External Events," dated September, 1997. Page 28 of the consultant's report, under (b)(2), they state "..it is unclear if the analysis considered the potential for diesel generator (lockout or starvation) failure caused by seismically induced activation of the co-located CO2 system. Also, it is unclear if the licensee analyzed the potential for icing or freezing or relays within the cable spreading room given seismically induced activation of the CO2 system, or the potential for the weight of the CO2 suppressant, which condenses on the cable trays, to fail safety-related cabling because of structural failure. Please address these three issues and reference documentation.	Address Seismic-induced loss of CO2 and its impact.	The electrical power reliability including the EDGs has been addressed in the SAMA. The risk contribution due to a failure of EDGs from a seismically failed CO2 system is expected to be minor. Therefore it should not significantly affect the cost/benefit evaluation of the SAMA associated with the EDGs.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
H	A	450	Split fraction event tree rules for seismic RCP seal modeling	The backstop split fraction SEX is seen in sequence 124 (DC01 ECCS AOT application) and others. This is a result of the lack of a rule that looks for no CCW flow with AS=S but with no support for CCP 1-1. The complementary rule exists (with no support for CCP 1-2). The result of this discrepancy is to give slightly more conservative results since a guaranteed failure is used in this particular instance rather than a calculated split fraction. Update SE event tree logic with provision for no CCP 1-1 support.	Need to add SF and rule for the scenarios with No CCW and no support for CCP 1-1.	Current results are conservative. No impact on the conclusion of the SAMA identification process.
J	A	1	Self assessment - initiating events -- expand ISLOCA calc discussion	More discussion should be added to ISLOCA calculation files C.4.7 and E.10 to justify the exclusion of tests or procedures contributing to the ISLOCA frequency.	Review related test procedure to determine if they contribute to ISLOCA.	This is a documentation issue and no impact on the SAMA application.
J	A	8	Self assessment - thermal/hydraulic analysis -- review FSAR success criteria for realism	In the future, success criteria based on the FSAR should be reviewed (i.e., number of accumulators that must inject for a large LOCA) to see if the success criteria can be made more realistic and less conservative. 12/19/02 EGD during the Beaver Valley Peer Certification, I learned that MAAP could not be used for the accumlators because it does not do a good job during the LOCA blow down phase when the accumulators are used.	To review applicability of FSAR success criteria to PRA to reduce conservatism .	If current results are conservative, then no impact on the SAMA application.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	11	Self assessment - data analysis -- compare random comp data with current data	Compare the random component failure data with a more current database or data used in other PRA'S (such as the data available in the WOG PSA comparison database) to ensure that the probability values are reasonable. Note that the original database used as the basis for the DCPP PRA model is 1988 vintage. Even though most of the data has been updated using plant specific information, a general review of the probability values is prudent.	Compare component failure rate used with other industry sources (e.g., WOG Comparison database). Use the most appropriate one. Results not expected to change significantly since they were updated with plant specific experience.	Not significant since risk results are not expected to change significantly.
J	A	43	CRVS alignment with both trains OOS	In calc file D.2.4, there is a maintenance alignment that has both trains of control room ventilation out of service, thus disabling HVAC to the SSPS room. Is this allowed by tech specs (remembering that CRVS has a support function for SSPS)? Should it be left in top event CV. It does not appear in initiator LOCV. Need to check the new ITS and ECGs.	Need to consider the validity of two CRVS trains out of service configuration. Note that operator would open door to SSPS room as compensatory measure.	If current results are conservative, then no impact on the SAMA application.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	48	Inconsistent number of "cold shutdowns"	In calc file E.5, they assume one cold shutdown per year in addition to a refueling every 1.5 years. The number of non-refueling cold shutdown is not consistent with DCPP operating history. Additionally, it uses variable ZDCNCS of 0.842 for the number of cold shutdowns to model demands, but calc file E.2 uses this same variable to model demands in afw which are actually hot shutdowns, of which there are more in DCPP history. Calc file E.2 also has a local variable @NRF of one refueling shutdown per year, while other calc files use one refueling every 18 months (which is no longer true). We should probobly setup some global variables that all the system calcs could reference for consistency basis. This appears in two system calc file. In both cases the cold shutdowns are added to the number of refueling shutdowns. However in H.1.5 we gather the number of cold shutdowns including refueling outages. Maybe the easiest way is to just gather the data differently (i.e. only gather as non-refueling cold shutdowns). Also note there is another action note because the number of cold shutdowns in e.2 appears to actually be used as number of hot shutdowns.	ZDCNCS is to be updated in the next data analysis update.	Not significant since very small impact on risk results is expected.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	52	C.9 quantification notes, LLOCA and accumulators	During the review of C.9 results, it was noticed for the LLOCA sequences that the accumulator failure was quite noticable. DCPP uses 3/3 success criteria, but other plants seem to be using 2/3 or maybe 1/3. It should be investiaged if the DCPP success criteria from the late 1980's is still appropiate, or should it be relaxed. Also note accumulators are taken credit in the time to core uncovery in the electric power recovery model.	Not implemented. To review success criteria of Accumulators for LLOCA in future update.	Current results are conservative. No impact on the SAMA application
J	A	54	C.9 quantification notes and CV vs SSPS	While reviewing the results of the C.9 quantification, it was noticed that there was a dependency between SSPS and its souce of HVAC. The question that comes to mind is what part of SSPS is needed in a mloca after the frist phases of the accident? It takes 90 minutes for the SSPS room to heat up (see section a FO DCPRA). I checked the LLOCA and it was the same way. But when I checked the general transient tree, the CV dependency was not there. I would expect this to be the other way around, i.e. gentran needs CV and the faster acting scenarios do not.	Investigate validity of dependency of SSPS on CRVS. (see Item #80)	Current results are conservative. No impact on the SAMA application

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	59	MLOCA recirc success criteria	While performing an evaluation of the risk significance of the "void" issue, the existing DC1997 model did not have the details needed. Hence a separate calcualtion had to be performed. Basically, the success criteria used in the PRA model has 2 out of 4 of the CCP'S and/or SIP's needed for a medium LOCA. In a more detailed thermal hydraulic calculation, it was noticed that the criteria could be relaxed to 1 out of 4 pumps in recirculation phase. PRA calculation 99-01 has further details.	Revise CH/SI success criteria to 1/4 from 2/4 for MLOCA in future update. (See PRA 99-01)	Current results are conservative. No impact on the SAMA application
J	A	68	Gather other plants' data on relief valves	During the review of the BOP model, it was noticed that we do not collect plant data for relief valves. We have been using the same failure rate since the LTSP for ZTVR2O and ZTVR2T. We should be gathering some plant data on these. Probably need more than just one type of relief valve (i.e., the relief valves on saltwater systems are subject to more failures than clean systems). Note we do gather specific data on the pressurizer PORV'S.	Consider developing plant specific data for relief valves.	Not significant as contribution of relief valves to CDF/LERF is not significant.
J	A	76	Battery charger unavailability in H.1.5 & D.2.1.2	The unavailability of battery chargers in the PRA appears to be less than actual plant practice. The average unavailability in the model is 37 hours per year which is noticability less than the duration of the one planned yearly "maintenance outage window" (MOW) of three to four days. Prior to the current model, battery chargers did not have a maintenance alignment in the PRA. In the DC1997 model, the DC train alignments were changed from the bus to the battery chargers, utilizing the existing databse variables of ZMBCHF and ZMBCHD. These vaiables	The battery charger maintenance unavailability is about twice that is being used in the current model. The impact on the DC Power unavailability due to this increase in maintenance unavailability is insignificant due to the availability of backup charger.	Impact on DC Power unavailability is insignificant. Also, the identified SAMA #3 is associated with the DC power supply. Therefore no impact on the conclusion of the SAMA identification process.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				appear to represent data collected over the normal range of the PRA. The duration of 69.9 hours seems reasonable but the frequency is 6.06E-5 which is significantly less than the yearly MOW frequency. The battery chargers used to be done in the outage. They were moved to on-line maintenance in the early to mid 1990's. The frequency in the PRA database is probably affected by the time when battery charger maintenance was not done on-line. Also in the 1997 update (for 1/1/95 to 9/30/96) there was no observed out of service times, which does not sound correct for yearly MOW'S. Finally, it needs to be checked to see if this data is just for the primary chargers (11, 12 and 132) or also for the backup chargers. The low unavailabilty was noticed by Tom Leserman when he was establishing an unavailability criterion for the battery chargers for the maintenance rule. In 2000 the battery chargers mow went from single shift to double shift since they are risk significant in the maintenance rule.	Need to update Battery Charger maintenance unavailability in future update.	

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	80	CRVS modeling, how is the split fraction logic done	When Tom Leserman was looking at control room ventilation, it was unclear how CRVS failure affected the SSPS since the CRVS is after SSPS in the MECHSP tree. On closer examination, it was noticed that some of the equipment that used SSPS acutation looked at both SSPS and top event OS (and some CV directly). It appears that OS0 gets selected if SA and SB are successful, but maybe also should have CV=S also. We checked the CCDP and it was almost 1.0 (but then again that was also true of the LTSP). The whole methodolgy of how CV failure affects the model needs to be checked out. At best all we may need to do is document what is there so we can better understand it. But when you look at AE'S 24, 25, 34 and 50, it appears that something probobly needs updating in the model. I ran a sensativity run with CV=S "ANDED" on the OS0 split fraction and the increase in CDF was only 1E-8. In C.13 two new maintenance cases were generated for the two trains of CRVS, and the results were similar. But the RAW for each of the trains for the other alingments (including the no maintenance alignment) were still off by an order of magnitude. Tome Leserman thinks that this maybe due to the dominance of the two trains maintenance alignment (MAINT3) which fails the system and has all its risk passed back to the assumed running train. The reason for SSPS is the 90 minute heatup of	Only dependency of SSPS on CRVS needs to be investigated. (See Items #54 and #111)	Current modeling of dependency of SSPS on CRVS is conservative. No impact on SAMA application.

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				the SSPS room with no action to provide alternate cooling. This could probably be looked at and updated, since the adjacent computer room appears to have excess cooling. Also the old tech specs has CRVS for equipment cooling (but does't say which equipment) and operator safety. The new its only has it for operator safety. The equipment section is not applicable to DCPP. For the SSPS room heatup, PLG-0637 Sec A.4.2.1 says 90 minutes, calc file D.1 Table D.1-1 Footnote #43 quotes 8 hours.		
J	A	82	Moving FCV-495/496 from ASW calc to CCW calc	When doing the ASW PRA system evaluation (D.2.6 Rev 7), it was determined that the failure (transfer close) of FCV-495/496 would be better modeled in the CCW calc file (D.2.7) where the heat excangers are located. The reason for this was that the ASW system did not know which heat exchanger was in service, so it was assumed that if either FCV-495 or FCV-496 closed that would fail the ASW system because it could not be determined if there was a flow path to the inservice heat exchanger. The rate of the FCV-495 and FCV-496 transfering closed is small and could be more realistically modeled with the CCW heat exchangers in top event CC. In the ASW system the current model says that asw is failed if either FCV-495 or FCV-496 has closed, and that is not realistic.	Model FCV-495/496 in CCWS. Note that these valves have been removed from the ASW model. Contribution of FCV to CCWS unavailability not significant.	Not significant since impact on CCWS unavailability is insignificant.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				Failure of FCV-495, FCV-496 have been taken out of the AS top event but has not been added to the CCW system.		
J	A	88	No common cause between instrument inverters D.2.1.7	There is no common cause failures modeled between any of the four vital instrument inverters. It is suggessted that common cause failure between the four inverters be developed. This is not expected to be a major effect on the model, since the inverters are reliable and contribute little to core damage. However, the common cause failure of the inverters will probably be a noticable effect on the worth of the individual inverter components.	Consider CCF of inverters. No industry data on CCF of inverters is currently available (See NUREG/CR-6268)	Pending availability of data, no impact on current SAMA application.
J	A	105	Electric power recovery, separate offsite and DEG	When looking at the plant trip of 5/15/00, it was noticed that electric power recovery in the model could not be applied to reflect the plant conditions durning that trip. Electric power recovery has both off-site and diesel generator recovery built into the split fraction. The plant at that time could not recovery off-site power due to in plant equipment failures, but could recovery the diesel generators. To model this in the future, additional recovery factors should be developed in calculation file G.4, so diesel only recovery is available for top event RE.	Recovery of DG only is modeled for the significant LOSP scenarios.	Current model includes the recovery of DG only for LOSP scenarios. No impact on conclusion of SAMA identification process since identified SAMAs #4 and #5 are associated with alternative onsite power source.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	111	MLOCA and CRVS lead to core damage	During the review of sequences for calc C.9, it was noticed that an MLOCA and failure of CRVS (top event CV) leads to core damage. The split fraction logic has failing all the ECCS equipment on failure of CRVS and operator failure (which operator failure is guaranteed under INIT=MLOCA). The actions are needed fast, but the CRVS will not fail that fast. This should be looked at more closely, since the CRVS will not fail the SSPS until a substantial time delay, and the automatic SSPS actions needed to combat a MLOCA are needed during the initial part of the transient. See sequence #58 in C.9 Rev 7.	Review the dependency of SSPS on CRVS for MLOCA scenarios.	Current modeling of dependency of SSPS on CRVS is conservative. No impact on SAMA application
J	A	121	Unfavorable exposure time (UET) and ATWT	On the longer cycles, the effect of ATWT becomes more pronounced with the UET. On initial investigation the DCPP model does not take this into account.	Investigate the effect of longer fuel cycle on the impact of ATWT scenarios. Effect is expected not to be significant.	Not significant since contribution from ATWT events on CDF/LERF is not significant.
J	A	143	AMSIV & IMSIV PORV challanges in D.1 & E.3	The present model has the PORV's as being challanged by AMSIV and IMSIV by water if the operators do not terminate safety injection in time (note present DC00 model has the operator action set to 1.0). This challenge is correct, but there is also a challange by steam initially. When all the MSIV'S go shut, there is a pressure rise which lifts the PORV's then there is a high pressure reactor trip. This happens seconds into the transient. This initial challange is not in the model. Presently the model probably overstates the effect of PORV challanges since it assumes there is a water challenge each time. When an updated operator action is put back in, the model will probably understate the effect of the PORV's since it does not account for the initial	Need to investigate if there are other conditions that would challenge the PORVs. In particular, steam relief if operator is successful in terminating the High pressure injection.	From PORV importance point of view, which is a concern to SAMA, the assumption of water challenge to PORV is more severe and conservative. Therefore the impact of this model conservatism should not affect the SAMA selection.

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				steam challange. Also note the closure of one MSIV will lead to a steam line isolation due to rapid steam pressure change, which in turn shuts the rest of the MSIV's.		
J	A	146	Add AMSAC CC to H.1.4	In calc file D.2.8 Rev.0, AMSAC, investigate the common cause failure rates for the components in reliability block lp. The failure rates in Rev. 0 are modified relay failure rates. Future Rev. May need new failure rates developed for any common cause combination of three trip logic modules. For further information, see documentation in calc file section D.2.8.1.3. 01/30/02 EGD The WOG SSPS WCAPs may have some failure rates that are more appropiate to use.	Use WOG SSPS failure rates in future updates. New data source is expected to have a small impact on the system reliability.	Not significant since impact on AMSAC unavailability is insignificant.
J	A	148	Add AMSAC maintenance unavailibility to H.1.2	AMSAC added to model DCC0 with calc file D.2.8 Rev. 0. Current revision contains estimated maintenance unavailibility. H.1.2 needs to be updated to include the AMSAC information.	Include AMSAC maintenance data to H.1.2 in data analysis update. Updated data is expected to have a small impact on the system reliability.	Not significant since impact on AMSAC unavailability is not significant.
J	A	160	RTB testing frequency in D.2.3	The testing frequency in the calculation file is each train every 30 days, where as tech specs is every 60 days. The frequecy should be changed to the tech spec 60 days.	Revise test freq. to once per 60 days. Current RTB unavailability result is conservative.	Since current RTB unavailability is conservative, there is no impact on SAMA application

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J	A	161	AMSAC UPS vs actuation maintenance unavailability	Presently AMSAC has one number for maintenance unavailability. But it was noticed that there are times when the UPS in cleared but AMSAC is still used. We should probably split these out into two different unavailabilities when we start collecting the actual plant data.	To develop AMSAC specific data. Updated data is expected to have a small impact on the system reliability.	Not significant since impact on AMSAC unavailability is not significant.
J	A	166	Need PORVs blocked maintenance alignment	PORVs need a maintenance alignment for when they are blocked and thus not available for RCS pressure relief (very important in ATWT), but are available for feed and bleed. This will simplify special risk assessments when a PORV is blocked. We should also try to obtain the historical data for the amount of time a PORV has been blocked and put it into the data collection.	Maintenance alignments for blocked PORV have been modeled in Top Event PO (ATWT response). Need to include actual plant data for such configurations in data update. Updated data is not expected to have a significant impact on PORV unavailability.	Not significant since impact on AMSAC unavailability is not significant and ATWT scenarios contribution to CDF/LERF is also not significant.
J	A	168	Multiple inverters cleared at the same time	The model does not prevent clearing multiple inverters at the same time, since each is in an independent top event. They sould be changed so that only one inverter can be in maintenance at a time by using an intermediate top event. This is also the same kind of arrangement that will be needed to implement common cause failure of inverters.	Conservative for clearing for multiple inverters. Need to know if there are common cause failure data for inverters. No industry data on CCF of inverters is currently available (See NUREG/CR-6268)	Current result is conservative. Pending availability of data, no impact on current SAMA application.

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J	A	169	Split out loss of 500 kV from turbine trip	Need to split out the contribution of loss of 500kV from the existing turbine trip initiator into a new initiator to be able to model the different plant impact. For some (but not all) loss of 500 kV will prevent from using the 500 kV backfeed since there may not be 500 kV available immediately. This was noticed when examining the plant response to the May 2000 fire event.	To separate loss of 500kV from Turbine Trip IE. When conservatively assume no credit for 500kV backfeed for Turbine Trip initiating event, the increase in CDF/LERF is less than 0.3 percent of the total plant CDF/LERF value.	Not significant since impact on CDF/LERF is not significant. Also identified SAMAs #4 and #5 are associated with the alternative onsite power source.
J	A	171	AMSAC needs some new failure rates	When Revision 0 of the AMSAC calculation file was done, some failure rates were not available so some surrogate failure rates were used. See Section D.2.8.1.2 for details. Need to find and/or develop more applicable failure rates for these components. One source maybe the recent work done by the WOG on SSPS.	Consider failure data for AMSAC - based on WOG data, in next data update. Updated data is expected to have a small impact on the system unavailability.	Not significant since impact on AMSAC unavailability is not significant.
J	A	172	Common cause instr channels for SSPS not modeled	While drafting the AMSAC calculation file (D.2.8), it was noticed that common cause of instrument channels for SSPS was not modeled. Need to model the common cause failure of instrument channels for both AMSAC and SSPS. It is expected that this would not be significant for AMSAC since many single channel failures will disable AMSAC. However SSPS needs two instrument chanels to fail before failing an input function and thus the common cause failure might be more noticable. Also include PRA calc D.2.8 for AMSAC	Model common cause failure of Instr. Channels for SSPS. Expected to have very small impact on the unavailability of SSPS.	Not significant since impact on SSPS unavailability is not significant.

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J	A	173	SSPS input channel unavailablity	Presently DCPP does not model input channel unavailability for SSPS or AMSAC. This can come from EAGLE 21 testing or channel calibration. In the past DCPP only did channel calibration in the outage. Most are done online. Prior to EAGLE 21, when a channel was tested it was placed in a trip condition there by reducing the chance of another channel failure disabling a trip. Now the tested channels are not placed into trip which reduces the chance of a plant trip, but increases the chance that another channel could fail thus disabling that input function. Also include AMSAC D.2.8	Instr. channel test now disables the channel for SSPS and AMSAC. Need to include test contribution. Expected to have very small impact on the unavailability of SSPS.	Not significant since impact on SSPS unavailability is not significant.
J	A	181	Bistable failure rates	The failure rates for BISTABLES in the DCPP database is different by a factor of 200 from what Westinghouse uses in their SSPS risk analysis.	Consider using WOG failure rate for bistables.	Not significant since scenarios associated or resulted from spurious actuation of bistables/SSPS have been analyzed and should not lead to a severe accident.
J	A	188	Implement updated SSPS failure rates	A0460719-32 was to investigate why SSPS split fractions went up noticably when, DCPP implemented the slave realy testing from quarterly to 18 months, even though the Westinghouse study cited there was no real increase. Some items were done in the DCC0 update, to reduce the risk of SSPS, but they did not address the basic problem, they just lessened the affects on other equipment. The DCPP SSPS model has many simplyfying assumptions, to fit into the RISKMAN software	Use WOG SSPS component failure rates in future update. Current results are conservative.	Since current SSPS unavailability is conservative, there is no impact on SAMA application

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				from the early 90's. A review of DCPP split fractions to South Texas split fractions show a noticable difference, some even over an order of magnitude. Below are some of the items to look at to improve the model: 1-the failure rates used by DCPP are dated and from the late 70's early 80's. In many cases they are not directly for SSPS components but similar. Westinghouse has done several studies over the last several years that have more appropiate failure rates for SSPS components. Examples are WCAP-15376-P, 15377-NP, 14117, 14334-NP, 14333-P. There is also a Westinhouse letter from GR Andre to Raymond Thierry which describes some of the differences. 2-South Texas Project has a lot more detail in their model. They generally, model at a lot lower level, where as DCPP models more at the functional level. 3-DCPP models that if one slave relay fails, then the whole function fails.		

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J	A	230	Model cross tying during SLOCA for RHR pumps	When the vital bus cross-tying was added to the model, it was not credited for LOCA (even SLOCA), because the time to crosstie outside the control room may not be adequate for some of the components used for the injection phase of the accident. However, there are some components that are used for high pressure recirculation, and there would be hours to crosstie the vital bus prior to needing that equipment (e.g., the RHRPs). We should look at the possibility of adding the crosstie capability for some components used later in accident mitigation. Instead of using the existing crosstie top events, it might be easier to implement with separate top events in the late tree.	Consider the cross-tying of buses for equipment needed for longer term mitigating actions. Current results are conservative.	Since current SSPS results are conservative, there is no impact on SAMA application
J	A	231	Modify loss of 500 kV failure rate	While reviewing the maintenance configuration for clearing startup power on-line, it was noticed that the loss of 500 kV failure rate as originally developed in PRA97-017 is too high for how it is being used in top event OGA. In top event OGA, it is used as a failure rate for loss of 500 kV to the plant. But in PRA97-017, the data was gathered as a 500 kV event that caused a plant trip, regarless if 500 kV was lost or not (i.e., a system disturbance). In fact, only one of the seven instances were a loss of 500 kV. In a second, the 500 was declared inoperable but was still available. The present number can be used as a generator trip. A lower number would be more applicable for loss oF 500 kV, or maybe use the present number as a momentarty loss and followed by another number to refflect the	Update loss of 500kV switchyard (ZT500K) failure frequency base on recent data in next data analysis update. Current 500kV switchyard unavailability is conservative.	Current 500kV switchyard unavailability is conservative. Also the identified SAMAs #4 and #5 are associated with alternative onsite power source. Therefore no impact on SAMA identification process.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				amount of time 500 kV was "instantly recovered".		
J	A	234	Accumulators used to mitigate seal LOCA	While researching information to respond to the NRC ASP preliminary evaluation of the May 2000 12 kV fire event, it was noticed that DCPP's time to core uncovery due to seal loca in SBO was about three times longer than Westinghouse analysis (5 vs 15 hours). This was researched by NOS in CHRONS 148151, 111456 and 147169. The transient analysis group re-reviewed this and the major difference was Westhinghouse only de-pressurized to 600 PSIG, whereas the PG&E MAAP runs went to about 300 PSIG. Thus, PG&E had the accumulators as another source of water before uncovery. This is not documented in any PRA calculation files. The modeling does not have any dependency between the accumulators and seal loca recovery in STADIC. The present DCPP model (DCC0 of 2001) only uses accumulators to mitigate a LLOCA. The dependency between accumulators and seal LOCA needs to be added to the model. The present importance calculations will understate the importance of accumulators.	Investigate the requirement of accumulator for seal LOCA. There is only a small difference between the probability of non-recovery of offsite power at 5 hours and that at 15 hours. This will have a small impact on the electric power recovery results if accumulators are not considered in the evaluation.	Impact on electric power recovery results is not significant. Also the identified SAMAs #4 and #5 are associated with alternative onsite power source. Therefore no impact on SAMA identification process.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	243	Contributors to failure of top event OG are missing	While developing PRA01-09 calculation file, it was noted that a couple of contributors to failure of top event OG (in particular, contributors to basic event OG-BK1A) may not have been included in the base model. These contributors include failure of the crosstie breaker to close, failure of Unit 1 SUT breaker to open, and HEP for performing the required actions. Evaluate this potential error.	Include additional contributors to top event OG via basic event OG-BK1A. Operator actions required for transfer of power from Unit 2 12kV Startup bus. (See Item #320). This model revision has a very small impact on the unavailability of power from the 230kV offsite grid.	Very small impact on the unavailability of power from the 230kV offsite grid and on the CDF/LERF. Also the identified SAMAs #4 and #5 are associated with alternative onsite power source. Therefore no impact on SAMA identification process.
J	A	254	ZHEAW4 not needed for runout of AFW pumps	Previous AE's have asked about putting the mdafw pump runout protection into the model to avoid the issue of runout for the pumps. When conducting the operator interviews for ZHEAW4, the scenario of the operators controlling the AFW flow to the turbine driven AFW PUMP, their answer was that is was not needed. The turbine driven AFW pumps does not have the runout protection control on the LCV's, because it is not subjected to run conditions due to piping configurations. This needs to be investigated and if true incorporated into the PRA model. Section 4.3.10.2 of DCM S-3B Rev 3 does provide some discussion of secondary system pipe ruptures.	Consider modeling of TDAFWP runout protection Result of current model is slightly conservative.	Since current AFW system unavailability results are conservative, there is no impact on SAMA application

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	260	Loss of power to LCV-8 controller may drain CST	During operator interviews for HEPs in December 2001, one of the opertors stated that if you lost power to the controller for LCV-8 (condensate makeup valve from the CST to the main condenser), it would drain the CST rather fast. (It sounded as if he was speaking from experience.) Abnormal procedure AP-26, "Loss Of Offsite Power," Revision 6, directs the operator to check this vavle closed in step 1.C. LCV-8 is an air operated valve that fails closed on loss of instrument air. It is controlled in the control room by 1-02-I-C-HC-1, whose power supply is 52-PV1529 (nonvital instrument panel PY-15), which has bus 1H as a normal source. 3/10/05 JKP It appears that this item has no impact on Calc E.2. Deleted E.2 from the affected calc list.	To include LCV-8 and the valve controller (loss of power) as a contributors to CST unavailability in Top Event AW, etc. The expected increase in AFW unavailability is about 6 percent for all support available case. The impact on the CDF/LERF is small. This impact is insignificant for the other boundary conditions.	Not significant since impact on risk results is small with respect to SAMA application.
J	A	261	OPS will not use transfer switch to restore power to CRVS train	One CRVS HEP exists in the model, to transfer CRVS to the backup train when the running train fails. All the actions are in the control room and the hep is used as such in the model. It is also used to model the operators transferring power to restore a CRVS train. That transfer switch is located in the auxiliary building, and would likely have a larger failure rate than what is used in ZHECV1. Additionally, during the december 2001 operator	HEPs ZHECV1 and ZHECV2 evaluated. Need to update CRVS models to incorporate operator actions. Impact on CRVS is insignificant. Also see Item #272	Not significant since impact on CRVS unavailability is small.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				interviews, the operators were firm that they would not align backup power when the selected source failed. Instead, they would simply open the door between the computer and SSPS rooms IAW CP M-10. The reasoning was that if they had lost the selected bus, they would be concentrating on restoring that bus for all of the loads, and when/if they got an alarm on SSPS room temperature, they would do the easy solution of opening the door, and not waste time changing the power source. We should quantify ZHECV1 for switching trains in the control room, delete its use for aligning to a separate power source, and add the HEP for opening the door between the SSPS and computer rooms as ZHECV2. Also not that the alternate power source is less important in the current model (as compared to the LTSP) because cross-tying the vital buses will restore power to the CRVS. This may or may not affect cdf. If there is an effect, it will be small, since CRVS worth is so small.		

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	263	CCW model has header 'C' and HEP combined	While researching HEPs, it was noticed that credit is taken for the operator to reduce heat loads for LLOCA (and MLOCA and SLBI), even though they may not have enough time. In other words, we are using the HEP for heat load reduction for all initiators. For LLOCA, MLOCA and SLBI, we generally have HI-HI containment pressure ("P" signal), which will isloate CCW non-vital header C. The various CCW calculations support one CCW pump as adequate for flow and heat loads when header C is isolated. This implies that failure of the HEP roughly approximates the hardware failure of header C to isolate. To more accurately model the worth of the HEP and FCV-355 (header C), they should probably be split out into separte items. Also note that the current modeling does not model the support for header C automatic isolation (SSPS for "P" signal and bus H for MOV power). This should have little affect on cdf or LERF, but will affect some basic event importances. 07/11/02 Further research during the NRC inspection also noticed FCV-355. We need to investigate if header 'C' isolation is required for phase "B" actuation even if two CCW pumps are running.	Revise rule for split fraction SE2 and SEF associated with SLBI initiator. This has an insignificant impact on the CDF/LERF.	Not significant since impact on CDF/LERF is also insignificant.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				11/12/02 Upon reviewing E.11 revision 9, it was noticed by AXA that the calc file talks about isolating header 'C' (implied by INIT=SLBI for general transient) and failing to trip the RCPS should give a failure of the seals. There is logic in top event for this in RP, but no logic for it in SE. So on INIT=SLBI if the RCPS are still running, and charging has failed the rules use split fraction SE2. But it should use SE2 only if -INIT=SLBI, and if INIT=SLBI (and charging AHS failed, it should use SEF). On reviewing past calcualtion files it appears that it has been this way since revision 1 and possibly revision 0 of C.4.2. A quick review of INIT=SLBI in PLG-0637 did not clarfy anything as none of the SBLI sequences showed any SE failing (almost like it was bypassed in the tree.)		
J	A	264	Add unavailability of Unit 2 cross-tie to recovery	The ability to use a Unit 2 DEG to supply Unit 1 during a station blackout is Appendix H of the eca series of emergency procedures. This was added to the PRA model as part of the 2000 update. However, the vital bus crosstie is periodically removed from service duing a Unit 2 refueling outage. This unavailability was not factored into the model, so there is some over-recovery. When we gather information for refueling outage unavailability, the vital bus crosstie should also be gathered. That unavailability should then be factored into the split fraction equation RER.	Include unavailability of Unit 2 x-tie when Unit 2 is in a refueling outage.	Not significant since impact on CDF/LERF is not significant.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	270	I-38 testing is modeled to two separate top events	STP I-38 tests both SSPS and reactor trip breakers. It is in the model as two separte sets of testing. The first is in SSPS (top events S1 through S6 in alignments TEST2 and TEST3) and the second is reactor trip (top event RT in alignments TEST1 and TEST2). So there is double counting of the testing unavailability. Additionally, this lets RISKMAN quantify time when opposite trains are out of service for testing at the same time. This conservatism should be a small overall contributor, but may affect component importance, particularly if dcpp goes for a risk-informed tech spec submital on SSPS/reactor trip. Also note there is another action to add the backup reactor trip breakers.	Need to account for STP I-38, define RT split fraction for specific SSPS train. This involves split fractions RT4 and RT5. Current model is slightly conservative with respect to opposite train testing of RT breakers and SSPS.	Since current SSPS and RT breaker results are conservative, there is no impact on SAMA application

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	272	Change HEP in CRVS to correspond to what OPS will actually perform	The modeling of HEPs in CRVS is done in four places, three in top event CV and one in top event CVI (initiator LOCV): 1. CVHE operator fails to align backup power and standby sub-train 2. CVHE1 operator fails to switch to backup power on running train 3. CVHE2 operator fails to start standby sub-train H 4. CVIHE2I operator fails to start standby sub-train H NOTE: ITEM 2 (CVHE1) is set to success in all split fractions. ITEM 1 (CVHE) is only used in one split fraction. Even though there are three HEPs only item 3 was analyzed under LOSP conditions and it was assumed that the number was conservative for all the other items (even though items 1 & 2 require manipulation outside the control room). The action to open the doors between the SSPS room and computer room for cooling is not in the model, but there has been some discussion of adding it in the past (we might have used it as part of a justification on some model simplifications). During the operator interviews (Dec 2001), the scenario for starting the standby sub-train was run through. Even though the procedures do not give explicit step-by-step instructions, the action was obvious. Even the no, who was looking at the annunciator response, was able to get to start the standby train. However, when it came to the scenario of aligning the backup source of power upon failure of the normal source, the operators chose instead to open the doors to the computer room, even though they were familiar with the two	PROPOSED CHANGES FOR TOP EVENT CV: 1. MODEL THE OPERATOR STARTING THE STANDBY SUB-TRAIN IF THE PRIMARY FAILS. 2. IF THE RUNNING TRAIN FAILS DUE TO LOSS OF SUPPORT (AC POWER), START THE STANDBY SUB-TRAIN. 3. IF IN EITHER #1 or #2 THE STANDBY TRAIN DOES NOT HAVE SUPPORT, OPEN THE DOORS FOR COOLING. FOR TOP EVENT CVI: 1. MODEL THE OPERATOR ONLY STARTING THE STANDBY SUB-TRAIN (LIKE IT IS PRESENTLY MODELED). NOTE: EXPECT THE HEPs FOR BOTH OF THESE EVOLUTIONS TO BE ABOUT AN ORDER OF MAGNITUDE LESS THAN THE EXISTING SLIM-MAUD QUANTIFIED HEP. See Item #261	Current model is conservative and has no impact on the SAMA application.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				sources. The reasoning was they have just lost a vital bus and are in the ECA procedures. They are concentrating on restoring that bus for more important and timely reasons than SSPS cooling. Instead of dispatching an operator to go into the auxiliary building to switch power around, they would open the doors to the room (in the procedure) because it was a lot quicker, and less distraction from the major evolutions. So items 1 and 2 would not get used, and in fact the only time they switch power around is when the primary bus is cleared for maintenance in an outage.		
J	A	277	E.8 has hard coded hours/year cont vent pens are open	E.8 has hard coded hours per year the containment ventilation penetrations are open. This number may be incorrect. It may be from when there was a tech spec limit on the hours per year the vent paths could be open. This does not affect CDF, but LERF impact is unknown.	Update the fraction of time the containment penetrations are open. Current result is conservative since period the penetration is based on Tech Spec limit instead of actual plant experience.	Current model is conservative and has no impact on the SAMA application.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	280	CCW pressurization unavailability is overstated in the model	While performing the LCO evaluation for H.1.2, the following inconsistency between the LCO sheets and the model (DCC0) was noticed. The CCW pressurization system was added to the model in the DC1997 update. Since it was a new system, the amount of time it was unavailable for maintenance was unknown, so 24 hours was assumed in alignment "MAINT4". For the H.1.2, a total of 4.62 hours was tabulated for the eight (reactor) year period. The amount of time in the alingment should up udated to be more consistent with the plant experience.	Update maintenance unavailability (in particular the maintenance duration) of Pressurization system in data analysis update. The maintenance contribution is modeled as a basic event CCSTPS_MN in the current model and is conservative. This affects the CDF only slightly.	Not significant since impact on CDF/LERF is not significant.
J	A	289	STP M-75 unavailability is not modeled in the average mode	While performing the LCO evaluation for H.1.2, the following inconsistency between the LCO sheets and the model (DCC0) was noticed. STP M-75 is now done online. The present frequency is every 18 months. There is an LAR in progress to increase this to 24 months like the rest of the refueling cycle length STPs. Presently, the unavailability is not accounted for in the system calculation file. It should be added. Presently, the STP is done in conjunction with the yearly DEG MOW. Therefore, operations will short cycle this test to every 12 months so it stays with the DEG MOW (to minimize unavailability).	Include contribution from M-75 (in conjunction with DEG MOW).	The identified SAMAs #4 and #5 are associated with alternative onsite power source. Therefore no impact on SAMA identification process.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	290	Split out turbine trip and generator trip	The present trip initiator includes both the generator trip (unit trip) and a plain turbine trip. However, the plant response to both of these items is not the same. A unit trip (generator trip) is caused by an elctrical fault. Most of these would preclude backfeeding from the 500 kV since the fault could be in that area. Even if the fault was not in that area, there would be a lot investigation to make sure that part was undamaged (read SHIFTS0 before fackfeeding. Also on a unit trip the auxiliary breaker is opened. If a deg was running the M-9A then it should carry the bus ok. It is unclear what the deg would do for say a loss of offsite power. The deg breaker may trip before the auxiliary breaker.	To separate Generator trip events from Turbine trip events and model generator trip IE. When conservatively assume no credit for 500kV backfeed for Turbine Trip initiating event, the increase in CDF/LERF is less than 0.3 percent of the total plant CDF/LERF value. (See Item #169)	Impact on CDF/LERF is not significant. Also the identified SAMAs #4 and #5 are associated with alternative onsite power source. Therefore no impact on SAMA identification process.
J	A	297	AS - 17 - Update the ATWT Model to new WOG Model "C"	The DCPRA includes a plant-specific model for ATWS response. Although the model appears to be reasonable, it is different than the Westinghouse Owners Group (WOG) model which the WOG plans to submit to NRC for review and approval for use in risk-informed licensing applications. In particular, the WOG model is intended to eventually allow plants to demonstrate acceptable risk with aggressive (high reactivity) fuel cycles. Although the DCPRA ATWS model is adequate for existing applications, the comment is directed at potential future ability to obtain fuel design and operating flexibility benefits using results of the WOG program.	Consider updating the ATWT model to conform with the WOG ATWS model. Note that DCPRA model is adequate.	No impact on SAMA application since current model is adequate for this application purpose.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	326	Four failure modes for SGTR	The draft of SDP for S/G inspection, AppendixJ, talks about 4 failure modes of tubes of which only one is usually modeled in the PRA. They are: 1-Spontaneous rupture of a tube (dcpp models as an initiator) 2-Steam side depressuzation causing a degraded tupe to rupture 3-Induced sgtr due to high and dry (dcpp models this from lerf) 4-ATWT with high RCS pressure causing a degraded tube to rupture We might want to consider enhancing our model if we need to address these issues in the future.	Consider additional failure modes for SGTR in future update. Some of these have been considered and found to have no significant impact on the CDFD/LERF.	Not significant since the impact on CDF/LERF is not significant.
J	A	331	Vital instrument backup transformers	The vital backup transformers have a maintenance unavailability of 3.417E-5/year which uses generic component unavailability. In the mid 1990's the maintenance on these items was moved from the outage to online. This will increase the maintenance unavailability significantly.	Update Transformer maintenance unavailability in data analysis. Contribution of transformer maintenance to Instrument AC power unavailability is insignificant.	Not significant since impact on Instrument AC power unavailability is insignificant and AC power's contribution to CDF/LERF is also insignificant.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	332	Class 1 PORV control channels change	The DCN which upgrades the controls for the two class one PORV's (to take credit for pressurizer over fill), moves the input channels from the normal control racks to EAGLE 21. This will probably change our split fraction logic, since a lot of it depends upon the source of power for the normal control channels. I am not sure how this dcn affects the switchability of which is the normal controlling channel (which we do not model since presently most of the time DCPP operates in the normal lineup).	This DCN would improve the reliability of the PORVs. Current model is conservative.	Current model is conservative and has no impact on the SAMA application.
J	A	356	2002 tech spec review for Unit 2 power	During the 2002 Tech Spec review the following items were noticed: D.2.1.4 top events BB and BBS have local variable @TSF at a yearly frequency for battery charger test STP M-12B. ITS is now a 2 your test. The charger test is usually done as part of the MOW which is on an 18 month interval. Therefore the frequency in the model should be changed from 12 months to 18 months	Revise test frequency from 12 to 18 months. Insignificant impact on results. CDF may decrease very slightly. Current model results are conservative.	Current model is conservative and has no impact on the SAMA application.
J	A	368	Add AMSAC failure rate variable to D.2.8 and H.1.5	During the data update in 2002/2003, failure data was collected for AMSAC (new variable ZTAMSR). Additional research should be performed to collect all AMSAC failure data (since 1988 for Unit 1 and 1989 for Unit 2) by searching pims for system 35 failures. This information should be used to develop a plant-specific prior failure rate, which should then be added to the AMSAC and data calculations.	Update database variable ZTAMSR for AMSAC with plant specific data. No significant impact on risk is expected.	Not significant since the impact on CDF/LERF is not significant.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	369	Loss of 2 vital buses does not mean phase C	In the documentation for top event RP, it has several conditions for loss of CCW to the RCP's. one of the conditions is on loss of two vital buses the operators will isolate header C to preserve CCW to the other loads. this is not what the operating procedure now says. the procedure has the operators reducing heat loads in accordance with Appendix B of AP-11, and there is nothing in there about isolating header C. In fact, the steps for isolating non-vital CCW to the containment have the operators ensuring that the RCPs have already been tripped. Also note if one of the two vital buses that is lost in "H" then there is no power to isolate header C. Top event CC already takes into account the reducing of heat loads if there is only one CCW pump running, and that HEP is not very time constrained. These double vital bus failures should not count as an immediate loss of CCW to the RCP'S, requiring them to be tripped within 10 minutes, and probably should be deleted. Since loss of two vital buses has a low probability, this should not make much difference to the overall CDF.	Current model is conservative. Impact on risk is not significant.	Not significant since current model is slightly conservative and the impact on CDF/LERF is not significant.
J	A	400	Database Variable ZTDRYP	The database variable ZTDRYP is used in E.12 Rev. 0 for the instrument air dryers 0-1 and 0-2. ZTDRYP is also used in D.2.4 Rev. 6 as the filter dryer for the control room ventilation system. According to Shobha (ABS), the instrument air dryers have a much higher failure rate than the control room filter dryer and should not use the same distribution. In fact, ZTDRYP has never been updated with a failure in 192,000 hours. The instrument air dryers, on	Consider developing separate failure rates for Instr. Air dryer and CRVS filter dryer. Currently both use ZTDRYP.	This may affect the unavailability of instrument air system but does not affect the identification of SAMA #9.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				the other hand, have at least a few failures that were not including when updating ZTDRYP. We may want to separate these distributions at some point.		
J	A	408	STP V-18E - New Procedure - Affects H.1.5 AFW test starts.	During H.3 Rev2. Procedure review, it was noticed that STP V-18E (a new procedure) tests check valves in the AFW system once per refueling outage. During the test, each of the pumps are started and FCV-95 is exercised. This should be accounted for in the next H.1.5 review.	Include STP V-18E in database update for AFW pump starts and FCV-95 demands. Data update issue. No significant impact on risk results is anticipated due to increase count in the number of equipment demand counts in data update.	Not significant since no significant impact on CDF/LERF.
J	A	409	Include STP V-13D, Vital 4KV Bus Startup Feeder Breakers Operability Test, in H.1.5.	In reviewing procedures for H.3 Rev 2, it was discovered that STP V-13D (new procedure, replaces PEP 63.01) should be included in the scope for H.1.5. This test procedure cycles the startup feeder breakers to determine operability following x-tie maintenance.	Include STP V-13D in database update for 4kV Bus startup breaker demands. Data update issue. No significant impact on risk results is anticipated due to increase count in the number of equipment demand counts in data update.	Not significant since no significant impact on CDF/LERF.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	417	Remove 4KV/480V dependency from Top Event OB.	Top Event OB does not include the Block valves. Therefore there should be no direct AC dependency. Remove the AC power dependency from the split fraction rules. This comment affect the split fraction rules for OB in GENTRN and SGTR trees.	Remove AC dependency from the OB split fraction rules via macros. Include short term DC power in macros. Current result is conservative.	Current model is conservative and has no impact on the SAMA application.
J	A	419	No Conditional SFs are considered for the Instrument AC channel Top Events.	Consider including the Conditional Split Fractions or common cause basic events in the Instrument AC top events.	Consider common cause failures of instrument channel equipment. No industry data on CCF of inverters is currently available (See NUREG/CR-6268) (see Item #88)	Pending availability of data, no impact on current SAMA application.
J	A	420	Consider Common Cause failures for Instrument AC system (I1, I2, I3, I4)	four instrument ac channels contain similar type of electrical/electromechanical equipments. However current model (2005) does not consider potential common cause failure.	Consider common cause failures of instrument channel equipment. No industry data on CCF of inverters is currently available (See NUREG/CR-6268). (see Items #88 and #419)	Pending availability of data, no impact on current SAMA application.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
J	A	421	Review effect of loss of 4KV bus H on Feed and Bleed function,	During the sequence review of FCDF IE=FS7, it was discovered that the feed and bleed function was guaranteed failed because of MACRO OBF2 was satisfied due to AH=F. The failure of a single 4KV bus (e.g., AH) should not necessarily disable DC panel 13 (DH) and a Class I PORV (i.e., PORV 456) and Instrument Air to 455C (via failure of containment isolation valve FCV-584). Please check if MACRO OBF2 definition is correct. This impacts all event trees with OB function.	Check OB dependency on AC power. (See Item #417)	Current model is conservative and has no impact on the SAMA application.
J	A	427	Modification of power supply to AMSAC	A design change will be made which will replace the existing power supply with a new and improved model, as well as changing the normal and by-pass sources of AC power. The second design change package installs the new panel PD27, which is the alternate DC source for the new power supply, fed from the Non-Vital Battery 25. There is no change in the system design function of the EJUPS replacement. However, the AC and DC input sources of the UPS have been enhanced, eliminating the battery back-up unit, EDU17, providing the DC source. Instead, the 120 Vdc UPS source is now fed through a DC distribution panel, PD-27, from station battery 25. The 120 Vac normal source was changed from the existing configuration where the normal and the bypass ac sources were fed from the same distribution panel, PYNM. The	Investigate and model (if necessary) new design for power supply to AMSAC. Design change would reduce the unavailability of AMSAC.	Current model is conservative and has no impact on the SAMA application.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				new normal 120 Vac source is now fed from a separate distribution panel, which is the PLAAA panel. And the bypass 120 Vac source, is the existing feed from the PYNM panel. The output of the new EJUPS is changed to 120 Vac, single phase, from the existing 208/120 Vac, three phase. This changes the load distribution panel PYUCC into a single phase, 120 Vac distribution panel.		
J	A	431	Vital battery life for electric power recovery	D.2.1.2 Rev. 8 references "" A Review of Systems Analysis in the DCPRA – Electric Power Systems (Except Diesel Generator and Diesel Fuel Transfer System)" DCL-90-046 when it states that the electric power recovery model assumes a battery life of 12 hours. A more recent update to the battery calculation has determined that the battery life for Batteries 12 and 22 is 5 hours 45 minutes and 7.5 hours for the other vital batteries (A0564461 AE01 from 369-DC Rev. 1). G.4 Revision 8 assumes a 7 hour battery life in calculating electric power recovery probabilities (used in DCPP MAAP calculation). Given that battery 12 has a calculated life of only 5 hours 45 minutes, determine the rationale for using the 7 hour MAAP assumption. Also, what impact does this lower battery life have on electric power recovery? (New MAAP runs	Investigate impact of battery of 5 hrs 45 mins on EPR results.	The identified SAMAs #4 and #5 are associated with alternative onsite power source. Therefore no impact on SAMA identification process.

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PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
				assuming 5 hours 45 minute battery life for certain functions and reanalysis with STADIC.)		
J	A	435	E.4 Rev. 7 incorrectly states that SI-1-8807A is powered by 480V bus G.	E.4 Rev. 7 incorrectly states that SI-1-8807A is powered by 480V bus G. Drawing 437916 sheet 1 and the block diagram component list in E.4 indicate that 8807A is off of bus F not G. This error is also in the split fraction impact for HRC (Bus G unavailable). Correct error by properly documenting and impacting 8807A.	Revise impact for split fraction HRC. Since loss of Bus F impacts 8807A, split fractions HR5 through HR8 should also be revised. The affected split fractions have very small impact on risk.	Not significant since impacted split fractions have very small impact on risk results.
J	A	437	Current model does not include ASW X-tie HEP for SLOCA	The current model DC01 credits ASW inter-unit cross-tie for SLOCA and non-SLOCA conditions. The same HEP is used for both scenarios and has timing based on a non-LOCA scenario. G.2 rev. 5 has HEPs for SLOCA sequences (ZHEAS6, ZHEAS7, ZHEAS8) but they are not used. If these are to be included, fire PRA HEPs need to be created from ZHEAS6,7, and 8.	Revise model to include x-tie for TLOCA scenarios. Corresponding HEP has been evaluated. These HEPs are somewhat higher than the HEPs currently used due to the shorter time windows involved. This would only impact sequences in which a transient induced small LOCA has occurred and both unit 1 ASW pumps have failed. The affected split	Not significant since impacted split fractions have very small impact on risk results.

Addendum 1 Evaluation of PRA Open Items / Issues on SAMA Process

PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
					fraction has small impact on risk.	
J	A	438	AFW Split Fraction AW7 is incorrect.	During sequences review for the fire PRA model it was noticed that the rule for AW7 was incorrect. AW7 represents the boundary condition in which instrument power to PCVs is lost and the TDP is not available. The rule for AW7 in GENTRN is for AFW Pump 3 and the TDP unavailable. I suggest that the rule INSTPWR*(-MDPA*MDPB)*TDP be changed to INSTPWR*(-MDPA*-MDPB)*TDP.	Revise rule for split fractions AW7, AW7B, AW7L in GENTRN event tree. The affected split fraction has insignificant impact on risk results.	Not significant since impacted split fractions have very small impact on risk results.
J	A	444	Evaluate success criteria for seal LOCA	Currently the injection success criteria for seal LOCA is 1 of 4 charging/SI pumps. In the event of a small seal LOCA where RCS pressure remains too high for SI, should this success criteria be changed. This point is also applicable to very small LOCAs which are not currently modeled in the DCPP PRA. The SLOCA initiator includes LOCAs from 0 to 2" equivalent break diameter.	Evaluate CH/SI success criteria for small seal LOCA, that is, cooldown and depressurization of RCS required for SI.	Except for very small breaks, during a SBLOCA, the RCS pressure will fall enough to allow the SIPs to inject. If AFW is available, even for these breaks, the pressure can be maintained so long as the CST has water. The combination of a small break and no AFW such that core SIP injection is not possible is still a slow enough process that operators would have to time to manually depressurize the

Addendum 1 Evaluation of PRA Open Items / Issues on SAMA Process

PRA Issue	Status	Record #	Action Title/ Applicable SR	Action Description	Current Status/ Comment	Importance to SAMA Application
						RCS to allow SIP injection
K	A	454	Dual Unit Initiators - Evaluate jellyfish attack	on 10/21/2008, high dP traveling screen alarms indicated the presence of debris loading at the intake. Unit 2 began ramping down and was manually tripped at power. Unit 1 successfully ramped to 50 percent. Evaluate this event as a dual unit trip precursor. Currently, DCPP does not consider a dual unit	Include such dual unit trip in model. This has been looked into. With an estimated frequency of about 0.05 per year and resulting in a reactor trip, the estimated CDF for this initiator is about 0.1 percent of the total CDF.	Not significant since impact on risk results is insignificant.
K	A	136	Split LCV into two IEFs - Kelp and other types	As an enhancement, split up the loss of condenser vacuum into two initiators for analysis purposes. The first one would be loss of condenser vacuum due to kelp clogging of the screens. The second would be the loss of condenser vacuum for all other causes. Insignificant impact.	Add new initiating event associated with intake screening plugging - kelp. Jelly fish, etc. See Item #454	Not significant since impact on risk results is insignificant.

References:

(1) Diablo Canyon Power Plant PRA Self-Assessment (Draft Report), ERIN Engineering and research, December 2006.
(2) Diablo Canyon Power Plant PRA Self-Assessment, ERIN P0114060001-2717 R1, January 2008
(3) “Review and Reevaluation of Specific Issues of internal Floods Analysis” by Scientech/Jacobson Engineering, Draft - January 2006.
(4) Diablo Canyon Follow-On Peer Review of HRA Update, Final Report, R-1736044-1728, July 31, 2007
(5) Transmittal of Resolution/Disposition of ASME PRA Peer Review Findings for LERF for Diablo Canyon Units 1 and 2, by Westinghouse Electric Company, LTR-RAM-II-07-021, November 30, 2007.
(6) Fauske and Associates, Inc. "MAAP - Modular Accident Analysis Program Users Manual," Technical Report on IDCOR Tasks 16.2 and 16.3, May 1983.

Note 1: Items #169, #290 and #250 have been resolved and removed since no action is required.
Note 2: Addendum 1 is from the Integrated Plant Examination Report